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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF AVISTA CORPORATION FOR THE AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC AND NATURAL GAS SERVICE TO ELECTRIC AND NATURAL GAS CUSTOMERS IN THE STATE OF IDAHO	)	CASE NO. AVU-E-11-01 CASE NO. AVU-G-11-01 DIRECT TESTIMONY OF TARA L. KNOX

FOR AVISTA CORPORATION

(ELECTRIC AND NATURAL GAS)

I. INTRODUCTION

Q. Please state your name, business address and present position with Avista Corporation.

A. My name is Tara L. Knox and my business address is 1411 East Mission Avenue, Spokane, Washington. I am employed as a Senior Regulatory Analyst in the State and Federal Regulation Department.

Q. Would you briefly describe your duties?

A. Yes. I am responsible for preparing the regulatory cost of service models for the Company, as well as providing support for the preparation of results of operations reports.

Q. What is your educational background and professional experience?

A. I am a graduate of Washington State University with a Bachelor of Arts degree in General Humanities in 1982, and a Master of Accounting degree in 1990. As an employee in the State and Federal Regulation Department at Avista since 1991, I have attended several ratemaking classes, including the EEI Electric Rates Advanced Course that specializes in cost allocation and cost of service issues. I have also been a member of the Cost of Service Working Group and the Northwest Pricing and Regulatory Forum, which are discussion groups made up of technical professionals from regional utilities and utilities throughout the United States and Canada concerned with cost of service issues.

Q. What is the scope of your testimony in this proceeding?

A. My testimony and exhibits will cover the Company's electric and natural gas cost of service studies performed for this proceeding. Additionally, I am sponsoring the electric and natural gas revenue normalization adjustments to the test year results of operations and the proposed Load Change Adjustment Rate (LCAR) to be used in the Power Cost Adjustment (PCA). A table of contents for my testimony is as follows:

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Q. Are you sponsoring any exhibits in this case?

A. Yes. I am sponsoring Exhibit 12 composed of six schedules as follows. Schedule 1, which illustrates the proposed Load Change Adjustment Rate calculation; Schedule 2, the electric cost of service study process description; Schedule 3, the electric cost of service study summary results; Schedule 4, the cost of service workshop presentation; Schedule 5, the natural gas cost of service study process description; and Schedule 6, the natural gas cost of service study summary results.

Q. Were these exhibits prepared by you or under your direction?

A. Yes, they were.

II. REVENUE NORMALIZATION

Electric Revenue Normalization

Q. Would you please describe the electric revenue adjustment included in Company witness Ms. Andrews pro forma results of operations?

A. Yes. The electric revenue normalization adjustment represents the difference between the Company's actual recorded retail revenues during the twelve months ended December 2010 test period, and retail revenues on a normalized (pro forma) basis. The total revenue normalization adjustment increases Idaho net operating income by $11,504,000, as shown in column (z) on page 8 of Ms. Andrews Exhibit No. 10, Schedule 1. The revenue normalization adjustment consists of three primary components: 1) re-pricing customer usage (adjusted for any known and measurable changes) at base tariff rates presently in effect, 2) adjusting customer loads and revenue to a 12-month calendar basis (unbilled revenue adjustment), and 3) weather normalizing customer usage and revenue[1].

Q. Since these three elements are combined into a single adjustment, would you please identify the impact

[1] Documentation related to this adjustment is detailed in the Knox workpapers accompanying this case.

(before taxes and revenue related expenses) of each component?

A. Yes. The re-pricing of billed usage comprises the majority of the change in test year revenue. The combined impact of the rate increase effective October 1, 2010[2], and the elimination of revenue and amortization expense from adder schedules (Schedule 59 Residential Exchange, Schedule 91 Public Purpose Tariff Rider, and Schedule 95 Optional Renewable Power[3]), is an <u>increase</u> in net revenue of $16,612,000. Re-pricing of unbilled calendar usage and elimination of unbilled adder schedule revenue and expense results in a net revenue <u>reduction</u> of $1,229,000[4]. Finally, the weather normalization adjustment <u>increases</u> revenue by $2,649,000. The combined impact of these elements is an increase of $18,032,000 which, after revenue-related expenses and income tax, results in the increase to net operating income of $11,504,000.

Q. Would you please briefly discuss electric weather normalization?

A. Yes. The Company's electric weather normalization adjustment calculates the change in kWh usage required to adjust actual loads during the twelve months ended December 2010 test period to the amount expected if weather had been normal. This adjustment incorporates the

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[2] IPUC Case No. AVU-E-10-1.

[3] Municipal Franchise Fee and Power Cost Adjustment revenues are eliminated in separate adjustments.

[4] The unbilled adjustment consists of removing December 2009 usage billed in January 2010 from the 2010 test year, adding December 2010 usage billed in January 2011 to the 2010 test year, and re-pricing the net adjustment to usage at October 1, 2010 rates.

effect of both heating and cooling on weather-sensitive customer groups. The weather adjustment is developed from regression analysis of ten years of billed usage per customer and billing period heating and cooling degree-day data. The resulting seasonal weather sensitivity factors (use-per-customer-per-heating-degree day and use-per-customer-per-cooling-degree day) are applied to monthly test period customers and the difference between normal heating/cooling degree-days and monthly test period observed heating/cooling degree-days.

Q. Have the seasonal weather sensitivity factors been updated since the last rate case?

A. Yes. The factors used in the weather adjustment are based on regression analysis of monthly billed usage per customer from January 2000 through December 2009 which is the most recent completed analysis. Autoregressive terms were included in the regressions in order to correct for autocorrelation in the data.

Q. What data did you use to determine "normal" heating and cooling degree days?

A. Normal heating and cooling degree days are based on a rolling 30-year average of heating and cooling degree-days reported for each month by the National Weather Service for the Spokane Airport weather station. Each year the normal values are adjusted to capture the most recent year with the oldest year dropping off, thereby reflecting the most recent information available at the end of each calendar year.

Q. Is this proposed weather adjustment methodology consistent with the methodology utilized in the Company's last general rate case in Idaho?

A. Yes, the process for determining the weather sensitivity factors and the monthly adjustment calculation is generally consistent with the methodology presented in Case No. AVU-E-10-1.[5]

Q. What was the impact of electric weather normalization on the twelve months ended December 2010 test year?

A. Weather was warmer than normal during the winter, and cooler than normal during the spring and summer of 2010. The adjustment to normal required the addition of 334 heating degree-days during the heating season[6] and 59 cooling degree-days. The total adjustment to Idaho sales volumes was an addition of 31,023,829 kWhs which is approximately 0.9% of billed usage.

__Natural Gas Revenue Normalization__

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[5] One difference may be observed between the cases. Due to the addition of autoregressive terms in the regression analysis, it was possible to include the desired ten years of data in this case, whereas in the prior case only five years of data had been used for Idaho electric customer groups in order to pass the Durbin Watson test for autocorrelation without autoregressive terms.

[6] The heating season includes the months of January through June and October through December.

Q. Would you please describe the natural gas revenue adjustment included in Ms. Andrews pro forma results of operations?

A. Yes. The natural gas revenue normalization adjustment is similar to the electric adjustment and represents the difference between the Company's actual recorded retail revenues during the twelve months ended December 2010 test period and retail revenues on a normalized (pro forma) basis. The adjustment includes the re-pricing of pro forma sales and transportation volumes at present rates using pro forma sales volumes that have been adjusted for unbilled sales, abnormal weather, and any material customer load or schedule changes. The rates used exclude: 1) Temporary Gas Rate Adjustment Schedule 155, which reflects the approved amortization rate for prior deferred gas costs approved in the Company's last PGA filing, 2) Public Purposes Rider Adjustment Schedule 191, and 3) Deferred State Income Tax Adjustment Schedule 199[7].

Q. Does the Revenue Normalization Adjustment contain a component reflecting normalized gas costs?

A. Yes. Purchase gas costs are normalized using the gas costs approved by the Commission in Case No. AVU-G-10-3, the Company's 2010 PGA filing, as set forth under Schedule 150. These gas costs, effective November 1, 2010, are applied to the pro forma retail sales volumes so that there is a matching of revenues and gas costs.

[7] Documentation related to this adjustment is detailed in the Knox workpapers accompanying this case.

Q. Have you determined the impact of each of the components of this adjustment?

A. Yes. The re-pricing of billed revenue and gas costs increased margin[8] by $1,263,000. Re-pricing unbilled revenue and gas costs decreased margin by $463,000, and the weather adjustment at present rates increased margin by $1,088,000.

The total net amount of the natural gas revenue normalization adjustment, which includes the related purchase gas cost normalization, is an increase to net operating income of $1,189,000, as shown in column (i), page 8 of Ms. Andrews Exhibit No. 10, Schedule 2.

Q. Would you please briefly discuss natural gas weather normalization?

A. Yes. The natural gas weather normalization adjustment is developed from a regression analysis of ten years of billed usage per customer and billing period heating degree-day data. The resulting seasonal weather sensitivity factors (use-per-customer-per-heating-degree day) are applied to monthly test period customers and the difference between normal heating degree-days and monthly test period observed heating degree-days. This calculation produces the change in therm usage required to adjust existing loads to the amount expected if weather had been normal.

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[8] The term "margin" in this context consists of revenues less gas costs and adder schedule amortization expenses but does not include the effect of revenue related expenses or income taxes.

Q. In your discussion of electric weather normalization you indicated that the adjustment utilized sensitivity factors from the ten year period January 2000 through December 2009. Is this true for natural gas as well?

A. Yes, the natural gas weather adjustment utilized updated weather sensitivity factors.

Q. What data did you use to determine "normal" heating degree days?

A. Normal heating degree-days are based on a rolling 30-year average of heating degree-days reported for each month by the National Weather Service for the Spokane Airport weather station. Each year the normal values are adjusted to capture the most recent year with the oldest year dropping off, thereby reflecting the most recent information available at the end of each calendar year.

Q. Is this proposed weather adjustment methodology consistent with the methodology utilized in the Company's last general rate case in Idaho?

A. Yes. The process for determining the weather sensitivity factors and the monthly adjustment calculation are consistent with the methodology presented in Case No. AVU-G-10-01.

Q. What was the impact of natural gas weather normalization on the twelve months ended December 2010 test year?

A. Weather was warmer than normal during the 2010 winter months, somewhat offset by a cooler than normal spring and fall. The adjustment to normal required the addition of 334 heating degree-days from January through June and October through December.[9] The adjustment to sales volumes was an addition of 3,225,558 therms which is approximately 2.8 percent of billed usage.

III. PROPOSED LOAD CHANGE ADJUSTMENT RATE

Q. What is the Load Change Adjustment Rate?

A. The Load Change Adjustment Rate (LCAR) is part of the PCA mechanism that prices the change in actual retail loads from the retail loads that were used to set the PCA base costs.

Q. In prior cases, wasn't this called the "Retail Revenue Credit Rate"?

A. Yes. September of last year, the Idaho Commission opened Case No. GNR-E-10-03 titled IN THE MATTER OF THE COMMISSION'S INQUIRY INTO LOAD GROWTH ADJUSTMENTS THAT ARE PART OF POWER COST ADJUSTMENT MECHANISMS. This proceeding resulted in a modified calculation methodology of the "Load Change Adjustment Rate" (LCAR) to be used beginning April 1, 2011 by all of the investor-owned electric utilities in their various power cost adjustment mechanisms.

[9] Heating degree days that occur during July through September do not impact the natural gas weather normalization adjustment as the seasonal sensitivity factor is zero for summer months.

Q. How is the new LCAR different from the former Retail Revenue Credit Rate?

A. The new LCAR includes only the proportion of production and transmission costs that are classified as energy-related in the Company's cost of service study to determine the rate. The former retail revenue credit rate used all production and transmission costs to determine the rate.

Q. How is the rate determined?

A. The proposed LCAR in this case is determined by computing the proposed revenue requirement on the production and transmission costs contained within Ms. Andrews' Idaho electric pro forma total results of operations. The production/transmission revenue requirement amount is then divided by the Idaho normalized retail load used to set rates in order to arrive at the average production and transmission cost-per-kWh embedded in proposed rates. This amount is then multiplied by the proportion of production and transmission costs classified as energy-related in the cost of service study.

Q. Do you have an exhibit schedule that shows the calculation of the proposed LCAR?

A. Yes. Exhibit No. 12, Schedule 1 begins with the identification of the production and transmission revenue, expense and rate base amounts included in each of Ms. Andrews' actual, restating, and pro forma adjustments to results of operations. The "Pro Forma Total Production and

Transmission Costs" at the bottom of page 1 shows the resulting production and transmission cost components.

Page 2 shows the revenue requirement calculation on the production and transmission cost components. The rate of return and debt cost percentages on Line 2 are inputs from the proposed cost of capital. The normalized retail load on Line 10 comes from the workpapers supporting the revenue normalization and energy efficiency load adjustments. Line 11 represents the average total production and transmission cost-per-kWh proposed to be embedded in Idaho customer retail rates. Lines 12 and 13 are values taken from the cost of service study supporting report titled <u>Functional Cost Summary by Classification at Uniform Requested Return</u> representing total costs at unity. Line 12 shows the amount of production and transmission costs classified as energy related, while Line 13 shows the total production and transmission costs in the study.

The resulting load change adjustment rate on Line 14 is $0.02633 per kWh or $26.33 per MWh. The calculation of the load change adjustment rate will be revised based on the final production and transmission costs and rate of return that are approved by the Commission in this case.

IV. ELECTRIC COST OF SERVICE

Q. Please briefly summarize your testimony related to the electric cost of service study.

A. I believe the Base Case cost of service study presented in this case is a fair representation of the costs to serve each customer group. The Base Case study shows Residential Service Schedule 1, Extra Large General Service Schedule 25, Pumping Service Schedule 31 and the Street and Area Lighting Schedules provide moderately less than the overall rate of return under present rates. General Service Schedule 11, Large General Service Schedule 21 and Extra Large General Service to Clearwater Paper Schedule 25P provide more than the overall rate of return under present rates.

Q. What is an electric cost of service study and what is its purpose?

A. An electric cost of service study is an engineering-economic study, which separates the revenue, expenses, and rate base associated with providing electric service to designated groups of customers. The groups are made up of customers with similar load characteristics and facilities requirements. Costs are assigned or allocated to each group based on (among other things), test period load and facilities requirements, resulting in an evaluation of the cost of the service provided to each group. The rate of return by customer group indicates whether the revenue provided by the customers in each group recovers the cost to serve those customers. The study results are used as a guide in determining the appropriate rate spread among the groups of customers. Exhibit No. 12, Schedule 2 explains the basic concepts involved in performing an electric cost of service study. It also details the specific methodology and assumptions utilized in the Company's Base Case cost of service study.

Q. What is the basis for the electric cost of service study provided in this case?

A. The electric cost of service study provided by the Company as Exhibit No. 12, Schedule 3 is based on the twelve months ended December 2010 test year pro forma results of operations presented by Ms. Andrews in Exhibit No. 10, Schedule 1.

Q. Would you please explain the cost of service study presented in Exhibit No. 12, Schedule 3?

A. Yes. Exhibit No. 12, Schedule 3 is composed of a series of summaries of the cost of service study results. The summary on page 1 shows the results of the study by FERC account category. The rate of return by rate schedule and the ratio of each schedule's return to the overall return are shown on Lines 39 and 40. This summary was provided to Company witness Mr. Ehrbar for his work on rate spread and rate design. The results will be discussed in more detail later in my testimony.

Pages 2 and 3 are both summaries that show the revenue-to-cost relationship at current and proposed revenue. Costs by category are shown first at the existing schedule returns (revenue); next the costs are shown as if all schedules were providing equal recovery (cost). These comparisons show how far current and proposed rates are from rates that would be in alignment with the cost study. Page 2 shows the costs segregated into production, transmission, distribution, and common functional categories. Line 44 on page 2 shows the target change in revenue which would produce unity in this cost study. Page 3 segregates the costs into demand, energy, and customer classifications. Page 4 is a summary identifying specific customer related costs embedded in the study.

The Excel model used to calculate the cost of service and supporting schedules has been included in its entirety both electronically and in hard copy in the workpapers accompanying this case.

Q. Does the Company's electric Base Case cost of service study follow the methodology filed in the Company's last electric general rate case in Idaho?

A. In most respects, yes. The Base Case cost of service study was prepared using the methodology applied to the study presented in Case No. AVU-E-04-01 through Case No. AVU-E-09-01 <u>except</u> that the <u>peak credit</u> classification of production and transmission costs has been revised. While a revision to the peak credit classification of production and transmission costs was also proposed in Case No. AVU-E-10-01, only the classification of transmission costs as 100% demand-related was accepted as part of the settlement in that case. Therefore the "Prior Methodology" refers to the study methodology last presented in Case No.

AVU-E-09-01 modified only to reflect the transmission costs classification change.

Q. Given that the specific details of this methodology are described in Exhibit No. 12, Schedule 2, would you please give a brief overview of the key elements and the history associated with those elements?

A. Yes. Production costs are classified to energy and demand in this case based on the system load factor. This is a new proposal due to the discussions at the cost of service workshop arising from the Settlement in Case No. AVU-E-10-01. Transmission costs are classified as 100% demand and allocated by weighted 12 month coincident peaks. While the transmission demand classification was accepted in the Settlement in Case No. AVU-E-10-01, the weighted 12 month coincident peak allocation is a new proposal discussed at the cost of service workshop required by the Settlement Stipulation in Case No. AVU-E-10-01.

Distribution costs are classified and allocated by the basic customer theory[10] accepted by the Idaho Commission in Case No. WWP-E-98-11. Additional direct assignment of demand related distribution plant has been incorporated to reflect improvements accepted by the Commission in Case No. AVU-E-04-01.

Administrative and general costs are first directly assigned to production, transmission, distribution, or customer relations functions. The remaining administrative

[10] Basic customer theory classifies only meters, services and street lights as customer-related plant; all other distribution facilities are considered demand-related

and general costs are categorized as common costs and have been assigned to customer classes by the four-factor allocator accepted by the Idaho Commission in Case No. AVU-E-04-01.

Q. You mentioned a cost of service workshop arising from the settlement in Case No. AVU-E-10-01. Please explain.

A. In Order No. 32070 from Case No. AVU-E-10-01 and AVU-G-10-01, the Commission approved an all-party Settlement Stipulation. In Section 11 of the Settlement Stipulation, beginning on page 5 it states:

> The Parties have otherwise agreed to exchange information and convene a public workshop, prior to the Company's next general rate case, with respect to the possible use of a revised peak credit method for classifying production costs, as well as consideration of the use of a 12 CP (whether "weighted" or not) versus a 7 CP or other method for allocating transmission costs.

The workshop was convened on February 8, 2011 at the Idaho Public Utilities Commission, and was attended by the key stakeholders regarding cost of service issues.[11] The Company's presentation and handouts from the workshop have been included as Schedule 4 of Exhibit No. 12.

Q. Regarding production cost classification, the workshop presentation emphasizes the benefits of the IRP based methodology Avista proposed in Case No. AVU-E-10-01. Why are you moving away from that approach in this case?

[11] Parties attending the workshop included Avista, IPUC Staff, Idaho Forest Group, Clearwater Paper, Idaho Conservation League, and Idaho Power Company.

A. A number of issues were raised in the workshop which led to a re-evaluation of that approach, as well as the applicability of an entirely future-based relationship in an embedded cost study. A system load factor alternative was raised during the workshop, and the Company determined that this approach to peak credit better met our requirements to improve the production and transmission cost classification process.

Q. What is the Company proposing in this case with regard to the peak credit methodology?

A. In this case the Company is proposing to use the system load factor to determine the proportion of the production function that is demand-related.[12] This single peak credit ratio is then applied uniformly to all production costs.

Q. How was the prior peak credit methodology determined and applied to production costs?

A. In the Company's prior cost of service studies, Avista's electric system resource costs were classified to energy and demand using a comparison of the replacement cost per kW of the Company's peaking units, to the replacement cost per kW of the Company's thermal and hydro plants (separately). This analysis created separate peak credit ratios applied to thermal plant and hydro plant costs. Fuel and system control expenses were classified

[12] One minus the load factor equals the demand percentage or peak credit ratio.

entirely to energy, and peaking plant related costs were classified entirely to demand.

Q. What are the benefits of using the system load factor to determine the peak credit ratio?

A. There are several benefits to the system load factor approach for identifying the demand-related proportion of production costs: 1) it is simple and straightforward to calculate, 2) it is directly related to the electric system and test year under evaluation, and 3) the relationship should remain relatively stable from year to year (i.e., not vary with changes in natural gas costs).

Q. What is the net effect of the proposed change in the peak credit method?

A. The net effect of this change is to <u>slightly</u> increase the overall level of production costs that are classified as demand-related. Using the prior method, approximately 31.97% of total production costs were classified as demand-related. Under the proposed method, 36.41% of total production costs are classified as demand-related. This change shifts costs away from high load factor customer groups (Schedules 21, 25, and 25P) as well as customer groups which have a limited contribution to system peak usage (pumping and street lighting).

Q. You also mentioned a change to the allocation of transmission costs, what are you proposing in this case?

A. All transmission costs are allocated to customer classes in this case by their weighted 12-month coincident peak demand. The peak demand by schedule at the time of each monthly system peak in the test year is weighted by the amount that the electric system peak demand in that month exceeded the annual average system demand as a proportion of the twelve month total excess system demand.

The weighting process is illustrated in Exhibit No. 12, Schedule 4, page 15. In this example, January system peak demand of 1,779 MW exceeded annual average demand (energy) of 1,134 aMW by 645 MW. 645 MW was 12.4% of the sum of each month's excess demand of 5,188 MW. Therefore, 12.4% of January coincident peak demand by schedule was included in the weighted 12CP allocation factor.

Q. In Case No. AVU-E-10-01 you had proposed a 7CP allocation factor for transmission costs, while in prior cases demand-related transmission costs were allocated by an unweighted 12 CP allocation factor. Why are you proposing the weighted 12 CP in this case?

A. The 7CP allocation was proposed in the last case to acknowledge that lower customer demands in the off-peak fall and spring seasons do not impose the same capacity utilization of the transmission facilities as the high demand winter and summer seasons. The weighted 12 CP allocation (developed for the workshop) is a more robust method to capture the seasonal impacts on transmission capacity utilization. As such, the Company considers this allocation to be a better representation of the demands on the transmission system than either the straight average of all monthly demands which does not recognize any seasonal differences, or the average of the seven highest months which ignores shoulder month demand entirely.

Q What is the impact on the study of moving from the 12CP (per the settlement in AVU-E-10-01) to the weighted 12CP in this case?

A. The net effect of this change is that more costs are assigned to both residential and street and area light customers, while all other customer classes benefit to varying degrees. Street and area lights only contribute to the system peak if that peak occurs after dark. This generally only happens during the winter months which naturally have more weight (i.e., more excess demand) than the spring and summer months. Similarly, due to heating loads, residential customers have their highest relative demand during winter months which have more weight than other times of the year.

Q. What are the results of the Company's electric cost of service study presented in this case?

A. The following table shows the rate of return and the relationship of the customer class return to the overall return (relative return ratio) at present rates for each rate schedule:

Illustration 1

Customer Class	Rate of Return	Return Ratio
Residential Service Schedule 1	6.27%	0.83
General Service Schedule 11/12	10.48%	1.38

Customer Class	Rate of Return	Return Ratio
Large General Service Schedule 21/22	8.65%	1.14
Extra Large General Service Schedule 25	6.38%	0.84
Extra Large General Service Clearwater Paper Schedule 25P	8.34%	1.10
Pumping Service Schedule 31/32	7.21%	0.95
Lighting Service Schedules 41 - 49	6.76%	0.89
Total Idaho Electric System	7.57%	1.00

As can be observed from the above table, residential, extra large general service, pumping service and lighting service schedules (1, 25, 31 and 41-49) show moderate under-recovery of the costs to serve them. The general service, large general service, and extra large Clearwater Paper schedules (11, 21, 25P) show moderate over-recovery of the costs to serve them. The summary results of this study were provided to Mr. Ehrbar as an input into development of the proposed rates.

Q. **Can you illustrate how the changes to the methodology applied to production and transmission costs impacted the cost of service study results?**

A. Yes. The following table contains the progression in rate of return and relative return ratio from the model run of the study using the prior method to the proposed Base Case method.

Illustration 2

Customer Class	AVU-E-10-01 Settlement Prior Method	Proposed Add Load Factor Peak Credit	Proposed Add Transmission Weighted 12CP

Customer Class	AVU-E-10-01 Settlement Prior Method		Proposed Add Load Factor Peak Credit		Proposed Add Transmission Weighted 12CP	
Schedule 1	6.48%	0.86	6.39%	0.84	6.27%	0.83
Schedule 11/12	10.49%	1.39	10.48%	1.38	10.48%	1.38
Schedule 21/22	8.49%	1.12	8.52%	1.12	8.65%	1.14
Schedule 25	6.19%	0.82	6.28%	0.83	6.38%	0.84
Schedule 25P	7.96%	1.05	8.18%	1.08	8.34%	1.10
Schedule 31/32	6.97%	0.92	7.06%	0.93	7.21%	0.95
Schedules 41 - 49	6.78%	0.90	6.84%	0.90	6.76%	0.89
Total Idaho	7.57%	1.00	7.57%	1.00	7.57%	1.00

This illustration shows the incremental impact of each change to the electric cost of service methodology. It also shows that the proposed electric cost of service changes had a relatively minor impact on the rate spread implications of the study.

V. NATURAL GAS COST OF SERVICE

Q. Please describe the natural gas cost of service study and its purpose.

A. A natural gas cost of service study is an engineering-economic study which separates the revenue, expenses, and rate base associated with providing natural gas service to designated groups of customers. The groups are made up of customers with similar usage characteristics and facility requirements. Costs are assigned in relation to each group's test year load and facilities requirements, resulting in an evaluation of the cost of the service provided to each group. The rate of return by customer group indicates whether the revenue provided by the customers in each group recovers the cost to serve those customers. The study results are one of the key inputs in determining the appropriate rate spread among the groups of customers. Exhibit No. 12, Schedule 5 explains the basic concepts involved in performing a natural gas cost of service study. It also details the specific methodology and assumptions utilized in the Company's Base Case cost of service study.

Q. What is the basis for the natural gas cost of service study provided in this case?

A. The cost of service study provided by the Company as Exhibit 12, Schedule 6 is based on the twelve months ended December 2010 test year pro forma results of operations presented by Ms. Andrews in Exhibit 10, Schedule 2.

Q. Would you please explain the cost of service study presented in schedule 6?

A. Yes. Exhibit 12, Schedule 6 is composed of a series of summaries of the cost of service study results. Page 1 shows the results of the study by FERC account category. The rate of return and the ratio of each schedule's return to the overall return are shown on lines 38 and 39. This summary is provided to Mr. Ehrbar for his work on rate spread and rate design. The results will be presented later in my testimony. Additional summaries show the costs organized by functional category (page 2) and classification (page 3), including margin and unit cost analysis at current and proposed rates. Finally, page 4 is a summary identifying specific customer related costs embedded in the study.

The Excel model used to calculate the cost of service and supporting schedules has been included in its entirety both electronically and hard copy in the workpapers accompanying this case.

Q. Does the Natural Gas Base Case cost of service study utilize the methodology from the Company's last natural gas case in Idaho?

A. Yes. The Base Case cost of service study was prepared using the methodology accepted by the Idaho Commission in Case No. AVU-G-04-01, and presented in AVU-G-08-01, AVU-G-09-01 and AVU-G-10-01.

Q. What are the key elements that define the cost of service methodology?

A. Allocations of gas costs reflect the current purchased gas tracker methodology. Underground storage costs are allocated by normalized winter throughput. Natural gas main investment has been segregated into large and small mains. Large usage customers that take service from large mains do not receive an allocation of small mains. Meter installation and services investment is allocated by number of customers weighted by the relative current cost of those items. System facilities that serve all customers are classified by the peak and average ratio that reflects the system load factor, then allocated by coincident peak demand and throughput, respectively. Demand side management costs (if any) are treated in the same way as system facilities. General plant is allocated by the sum of all other plant. Administrative & general expenses are segregated into labor-related, plant-related, revenue-related, and "other". The costs are then allocated by factors associated with labor, plant in service, or revenue, respectively. The "other" A&G amounts get a combined allocation that is one-half based on O&M expenses and one-half based on throughput. A detailed description of the methodology is included in Schedule 5.

Q. **What are the results of the Company's natural gas cost of service study?**

A. I believe the Base Case cost of service study presented in this filing is a fair representation of the costs to serve each customer group. The study indicates that the General Service (primarily residential) Schedule (101) is providing slightly less than the overall return (unity), and Large General, Interruptible and Transportation Service Schedules (111, 131 and 146) are providing slightly more than unity. All schedules are currently providing return ratios that are relatively close to unity.

The following table shows the rate of return and the relative return ratio at present rates for each rate schedule:

Illustration 3

Customer Class	Rate of Return	Return Ratio
General Firm Service Schedule 101	7.09%	0.97
Large Firm Service Schedule 111/112	8.37%	1.15
Interruptible Service Schedule 131/132	7.87%	1.08
Transportation Service Schedule 146	7.57%	1.04
Total Idaho Natural Gas System	7.31%	1.00

The summary results of this study were provided to Mr. Ehrbar as an input into development of the proposed rates.

Q. Does this conclude your pre-filed direct testimony?

A. Yes.

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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF AVISTA CORPORATION FOR THE AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC AND NATURAL GAS SERVICE TO ELECTRIC AND NATURAL GAS CUSTOMERS IN THE STATE OF IDAHO	CASE NO. AVU-E-11-01 CASE NO. AVU-G-11-01 EXHIBIT NO. 12 TARA L. KNOX

FOR AVISTA CORPORATION

(ELECTRIC AND NATURAL GAS)

AVISTA UTILITIES

AVERAGE PRODUCTION AND TRANSMISSION COST
IDAHO ELECTRIC
TWELVE MONTHS ENDED DECEMBER 31, 2010

Column	Description of Adjustment	(000's)	Production/Transmission Revenue	Production/Transmission Expense	Production/Transmission Rate Base
b	Results Report		132,780	246,222	367,353
c	Deferred FIT Rate Base			-	(56,171)
d	Deferred Gain on Office Building			-	-
e	Colstrip 3 AFUDC Elimination			191	1,493
f	Colstrip Common AFUDC			-	774
g	Kettle Falls & Boulder Park Disallow.			-	(1,880)
h	Customer Advances			-	-
i	Weatherizn and DSM Investment			-	65
j	Restating CDA Settlement			29	(317)
k	Restating CDA Settlement Deferral			18	166
l	Restating CDA/SRR CDR			348	(68)
m	Restating Spokane River Deferral			3	31
n	Restating Spokane River PM&E Deferral			20	145
o	Restating Montana Lease			46	996
p	Working Capital			-	-
	Actual		132,780	246,877	312,587
q	Eliminate B & O Taxes			-	
r	Property Tax			297	
s	Uncollect. Expense			-	
t	Regulatory Expense			-	
u	Injuries and Damages			-	
v	FIT			-	
w	Idaho PCA			(3,227)	
x	Nez Perce Settlement Adjustment			(17)	
y	Eliminate A/R Expenses			-	
z	Revenue Normalization Adjustment			6,058	
aa	Misc A&G Restating Adjs			(1)	
ab	Restating Incentive Adj			-	
ac	Restating CS2 Levelized Adj			280	
ad	Colstrip Stlmnt Exp			(230)	
ae	Removal CCX Revenue			342	
af	O&M Savings			(99)	
ag	Restate Debt Interest			-	
	Restated Total		132,780	250,280	312,587
PF1	Pro Forma Power Supply		(114,526)	(105,403)	-
PF2	Pro Forma Energy Efficiency Load Adjustment		1,201	(1,157)	-
PF3	Pro Forma Labor Non-Exec			371	-
PF4	Pro Forma Labor Exec			2	-
PF5	Pro Forma Transmission Rev/Exp		(355)	832	-
PF6	Pro Forma Capital Add 2010			115	2,477
PF7	Pro Forma Capital Add 2011			552	(134)
PF8	Pro Forma Capital Add 2012			138	(2,438)
PF9	Pro Forma Noxon Gen 2011 & 2012			217	4,650
PF10	Pro Forma Employee Benefits			52	-
PF11	Pro Forma Insurance			-	-
PF12	Pro Forma Vegetation Management			-	-
	Pro Forma Total		19,100	145,999	317,142

AVISTA UTILITIES

AVERAGE PRODUCTION AND TRANSMISSION COST
IDAHO ELECTRIC
TWELVE MONTHS ENDED DECEMBER 31, 2010

Proposed Production and Transmission Revenue Requirement
Calculation of Load Change Adjustment Rate at Proposed Return

Line			($000's)	Debt Cost
1	Prod/Trans	Pro Forma Rate Base	$317,142	
2		Proposed Rate of Return	8.490%	3.020%
3	Rate Base	Net Operating Income Requirement	$26,925	
4	Tax Effect	Net Operating Income Requirement (Rate Base x Debt Cost x -35%)	($3,352)	
5	Net Expense	Net Operating Income Requirement (Expense - Revenue)	126,899	
6	Tax Effect	Net Operating Income Requirement (Net Expense x -.35%)	($44,415)	
7	Total Prod/Trans	Net Operating Income Requirement	$106,058	
8	1 - Tax Rate	Conversion Factor (Excl. Rev. Rel. Exp.)	0.65	
9	Prod/Trans	Revenue Requirement	$163,165	
10	ID Test Year Normalized Retail Load MWh		3,358,927	
11	Prod/Trans Rev Requirement per kWh		$ 0.04858	
12	Cost of Service Energy Classified Production/Transmission Costs		$ 89,949	
13	Cost of Service Total Production/Transmission Costs		$ 165,977	
14	Load Change Adjustment Rate per kWh (Line 11 * Line 12 / Line 13)		**$ 0.02633**	

1. ELECTRIC COST OF SERVICE

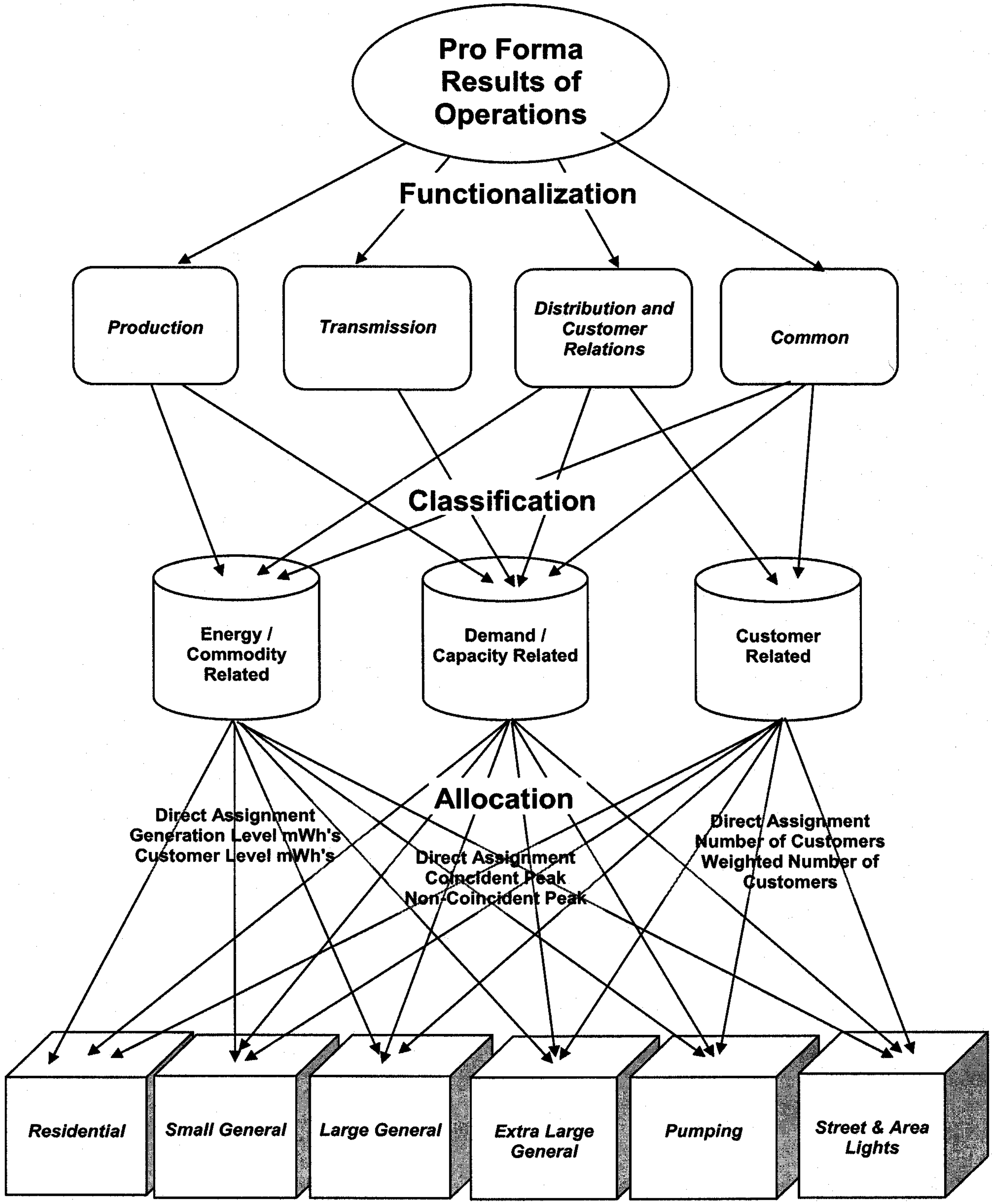
A cost of service study is an engineering-economic study, which apportions the revenue, expenses, and rate base associated with providing electric service to designated groups of customers. It indicates whether the revenue provided by the customers recovers the cost to serve those customers. The study results are used as a guide in determining the appropriate rate spread among the groups of customers.

There are three basic steps involved in a cost of service study: functionalization, classification, and allocation. See flow chart below.

First, the expenses and rate base associated with the electric system under study are assigned to functional categories. The uniform system of accounts provides the basic segregation into production, transmission, and distribution. Traditionally customer accounting, customer information, and sales expenses are included in the distribution function and administrative and general expenses and general plant rate base are allocated to all functions. In this study I have created a separate functional category for common costs. Administrative and general costs that cannot be directly assigned to the other functions have been placed in this category.

Second, the expenses and rate base items that cannot be directly assigned to customer groups are classified into three primary cost components: energy, demand or customer related. Energy related costs are allocated based on each rate schedule's share of commodity consumption. Demand (capacity) related costs are allocated to rate schedules on the basis of each schedule's contribution to peak demand. Customer related items are allocated to rate schedules based on the number of customers within each schedule. The number of customers may be weighted by appropriate factors such as relative cost of metering equipment. In addition to these three cost components, any revenue related expense is allocated based on the proportion of revenues by rate schedule.

ELECTRIC COST OF SERVICE STUDY FLOWCHART



Pro Forma Results of Operations by Customer Group [1]

1 Customer classes shown in this flowchart are illustrative and may not match the Company's actual rate schedules.

The final step is allocation of the costs to the various rate schedules utilizing the allocation factors selected for each specific cost item. These factors are derived from usage and customer information associated with the test period results of operations.

BASE CASE COST OF SERVICE STUDY

Production Classification (Load Factor Peak Credit)

This study utilizes a Peak Credit methodology to classify production costs into demand and energy classifications. The Peak Credit method acknowledges that all energy production costs contain both capacity and energy components as they provide energy throughout the year as well as capacity during system peaks. The peak credit ratio (the proportion of total production cost that is capacity related) is determined using the electric system load factor inherent in the test year. The share of production costs attributable to demand is one minus the load factor (average MW divided by peak MW) which is 36.41% for the 2010 test year, The same classification ratio is applied to all production costs.

Production Allocation

Production demand related costs are allocated to the customer classes by class contribution to the average of the twelve monthly system coincident peak loads. Although the Company is usually technically a winter peaking utility, it experiences high summer peaks and careful management of capacity requirements is required throughout the year. The use of the average of twelve monthly peaks recognizes that customer capacity needs are not limited to the heating season. Energy related costs are allocated to class by pro forma annual kilowatthour sales adjusted for losses to reflect generation level consumption.

Transmission Classification and Allocation

Transmission costs are classified as 100% demand related due in part to the fact that the facilities are designed for meeting system peak loads. These costs are then allocated to the customer classes by class contribution to the monthly system coincident peak loads weighted by the proportion the electric system peak demand exceeded annual average demand in each month. This method ecognizes that lower customer demands in the off-peak fall and spring seasons do not impose the same capacity utilization of the transmission facilities as the high demand winter and summer seasons.

Distribution Facilities Classification (Basic Customer)

The Basic Customer method considers only services and meters and directly assigned Street Lighting apparatus (FERC Accounts 369, 370, and 373 respectively) to be customer related distribution plant. All other distribution plant is then considered demand related. This division delineates plant which benefits an individual customer from plant which is part of the system. The basic customer method provides a reasonable, clearly definable division between plant that provides service only to individual customers from plant that is part of the interconnected distribution network.

Customer Relations Distribution Cost Classification

Customer service, customer information and sales expenses are the core of the customer relations functional unit which is included with the distribution cost category. For the most part they are classified as customer related. Exceptions are sales expenses which are classified as energy related and uncollectible accounts expense which is considered separately as a revenue conversion item. Demand Side Management expenses (if any) recorded in Account 908 are also considered separately from the other customer information costs.

Any demand side management investment and amortization included in base rates would be classified implicitly to demand and energy by the sum of production plant in service, then allocated to rate schedules by coincident peak demand and energy consumption respectively. At this point in time, the Company's demand side management investments in base rates have been fully amortized except for some minor outstanding loan balances that will remain on the books until satisfied. All current demand side management costs are managed through the Schedule 91 Public Purpose Tariff Rider balancing account which is not included in this cost study.

Distribution Cost Allocation

Distribution demand related costs which cannot be directly assigned are allocated to customer class by the average of the twelve monthly non-coincident peaks for each class. Distribution facilities that serve only secondary voltage customers are allocated by the non-coincident peak excluding primary voltage customers or number of customers excluding primary voltage customers. This includes line transformers, services, and secondary voltage overhead or underground conductors and devices. The costs of specific substations and related primary voltage distribution facilities are directly assigned to Extra Large General Service customers based on their load ratio share of the substation capacity from which they receive service.

Most customer costs are allocated by average number of customers. Weighted customer allocators have been developed using typical current cost of meters, estimated meter reading time, and direct assignment of billing costs for hand-billed customers. Street and area light customers are excluded from metering and meter reading expenses as their service is not metered.

Administrative and General Costs

Administrative and general costs which are directly associated with production, transmission, distribution, or customer relations functions are directly assigned to those functions and allocated to customer class by the relevant plant or number of customers. The remainder of administrative and general costs are considered common costs, and have been left in their own functional category. These common costs are classified by the implicit relationship of energy, demand and customer within the four-factor allocator applied to them. The four-factor allocator consists of a 25% weighting of each of the following: 1) operating & maintenance expenses excluding resource costs, labor expenses, and administrative and general expenses; 2) operating and maintenance labor expenses excluding administrative and general labor expenses; 3) net production, transmission, and distribution plant; and 4) number of customers.

Revenue Conversion Items

In this study uncollectible accounts and commission fees have been classified as revenue related and are allocated by pro forma revenue. These items vary with revenue and are included in the calculation of the revenue conversion factor. Income tax expense items are allocated to schedules by net income before income tax adjusted by interest expense.

For the functional summaries on pages 2 and 3 of the cost of service study, these items are assigned to component cost categories. The revenue related expense items have been reduced to a percent of all other costs and loaded onto each cost category by that ratio. Similarly, income tax items have been reduced to a percent of net income before tax then assigned to cost categories by relative rate base (as is net income).

The following matrix outlines the methodology applied in the Company Base Case cost of service study.

Line	Account	Functional Category	Classification	Allocation
	Production Plant			
1	Thermal Production	P = Production	Demand/Energy by Load Factor Peak Credit	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
2	Hydro Production	P = Production	Demand/Energy by Load Factor Peak Credit	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
3	Other Production (Coyote Springs)	P = Production	Demand/Energy by Load Factor Peak Credit	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
4	Other Production	P = Production	Demand/Energy by Load Factor Peak Credit	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
	Transmission Plan			
5	All Transmission	T = Transmission	Demand	D02 Weighted 12 Month Coincident Peak Demand (Excess Peak Percentage)
	Distribution Plan			
6	360 Land	D = Distribution	Demand	D03 Non-coincident Peak Demand (NCP)
7	361 Structures	D = Distribution	Demand	D04/D05/D06 Direct Assign Large / Non-coincident Peak Demand Excl DA
8	362 Station Equipment	D = Distribution	Demand	D04/D05/D06 Direct Assign Large / Non-coincident Peak Demand Excl DA
9	364 Poles Towers & Fixtures	D = Distribution	Demand	D04/D05/D07/D08 Direct Assign Large & Lights / NCP Excl DA / NCP Secondary
10	365 Overhead Conductors & Devices	D = Distribution	Demand	D04/D05/D07 Direct Assign Large / NCP Excl DA / NCP Secondary
11	366 Underground Conduit	D = Distribution	Demand	D04/D05/D07 Direct Assign Large / NCP Excl DA / NCP Secondary
12	367 Underground Conductors & Devices	D = Distribution	Demand	D04/D05/D07 Direct Assign Large / NCP Excl DA / NCP Secondary
13	368 Line Transformers	D = Distribution	Demand	D07 Non-coincident Peak Demand Secondary
14	369 Services	D = Distribution	Customer	C02 Secondary Customers unweighted Excl Lighting
15	370 Meters	D = Distribution	Customer	C04 Customers weighted by Current Typical Meter Cost
16	373 Street and Area Lighting Systems	D = Distribution	Customer	C05 Direct Assignment to Street and Area Lights
	General Plant			
17	All General	O=Other	Demand/Energy/Customer by Corp Cost Allocator	S23 25% direct O&M, 25% direct labor, 25% net direct plant, 25% number of customers
	Intangible Plant			
18	301 Organization	O=Other	Energy/Customer by Corp Cost Allocator	S23 25% direct O&M, 25% direct labor, 25% net direct plant, 25% number of customers
19	302 Franchises & Consents - Hydro Relicensing	P = Production	Demand/Energy by Load Factor Peak Credit	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
20	303 Misc Intangible Plant - Transmission Agreements	T = Transmission	Demand	D02 Weighted 12 Month Coincident Peak Demand (Excess Peak Percentage)
21	303 Misc Intangible Plant - Software	O=Other	Demand/Energy/Customer by Corp Cost Allocator	S23 25% direct O&M, 25% direct labor, 25% net direct plant, 25% number of customers
	Reserve for Depreciation/Amortizatio			
22	Intangible	P/T/O	Follows Related Plant	S01/S02/S23 Sum of Production Plant / Sum of Transmission Plant / Corp Cost Allocator
23	Production	P = Production	Follows Related Plant	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
24	Transmission	T = Transmission	Follows Related Plant	D02 Weighted 12 Month Coincident Peak Demand (Excess Peak Percentage)
25	Distribution	D = Distribution	Follows Related Plant	D03/D04/D05/D06/D07/D08/C02/C04/C05 - See Related Plant
26	General	O=Other	Demand/Energy/Customer by Corp Cost Allocator	S23 25% direct O&M, 25% direct labor, 25% net direct plant, 25% number of customers
	Other Rate Base			
27	252 Customer Advances for Construction	D = Distribution	Customer	S13 Sum of Account 369 Services Plant
28	282/190 Accumulated Deferred Income Tax	P/T/D/O by Plant Balances	Follows Related Plant	S01/S02/S03/S04 Sums of Production / Transmission / Distribution / General Plant
29	Gain on Sale of General Office Building	O=Other	Demand/Energy/Customer by Corp Cost Allocator	S23 25% direct O&M, 25% direct labor, 25% net direct plant, 25% number of customers
30	Hydro Relicensing Related Settlements	P = Production	Demand/Energy by Load Factor Peak Credit	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
31	Demand Side Management Investment	DSM	Demand/Energy from Production Plant	S01 Sum of Production Plant
32	Working Capital	P/T/D/G	Demand/Energy/Customer as in related Plant	S06 Sum of Production, Transmission, Distribution, and General Plant
	Production O&M			
33	Thermal	P = Production	Demand/Energy by Load Factor Peak Credit	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
34	Thermal Fuel (501)	P = Production	Demand/Energy by Load Factor Peak Credit	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
35	Hydro	P = Production	Demand/Energy by Load Factor Peak Credit	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption

IPUC Case No. AVU-E-11-01 Methodology Matrix
Avista Utilities Idaho Jurisdiction
Electric Cost of Service Methodology

Line	Account	Functional Category	Classification	Allocation
	Production O&M (continued)			
1	Water for Power (536)	P = Production	Demand/Energy by Load Factor Peak Credit	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
2	Other (Coyote Springs)	P = Production	Demand/Energy by Load Factor Peak Credit	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
3	Other Fuel (547)	P = Production	Demand/Energy by Load Factor Peak Credit	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
4	Other	P = Production	Demand/Energy by Load Factor Peak Credit	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
5	Purchased Power and Other Expenses (555 and 557)	P = Production	Demand/Energy from Production Plant	S01 Sum of Production Plant
6	System Control & Misc (556)	P = Production	Demand/Energy by Load Factor Peak Credit	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
	Transmission O&M			
7	All Transmission	T = Transmission	Demand	D02 Weighted 12 Month Coincident Peak Demand (Excess Peak Percentage)
	Distribution O&M			
8	580 OP Super & Engineering	D = Distribution	Demand/Customer from Other Dist Op Exp	S16 Sum of Other Distribution Operating Expenses
9	581 Load Dispatching	D = Distribution	Demand	D03 Non-coincident Peak Demand
10	582 Station Expenses	D = Distribution	Demand	S09 Sum of Account 362 Station Equipment
11	583 Overhead Lines	D = Distribution	Demand	S10 Sum of Accounts 364 and 365 Poles, Towers, Fixtures & Overhead Conductors
12	584 Underground Lines	D = Distribution	Demand	S11 Sum of Accounts 366 and 367 Underground Conduit & Underground Conductors
13	585 Street Lights	D = Distribution	Customer	S15 Sum of Account 373 Street Light and Signal Systems
14	586 Meters	D = Distribution	Customer	S14 Sum of Account 370 Meters
15	587 Customer Installations	D = Distribution	Customer	S13 Sum of Account 369 Services
16	588 Misc Operating Expense	D = Distribution	Demand/Customer from Other Dist Op Exp	S16 Sum of Other Distribution Operating Expenses
17	589 Rents	D = Distribution	Demand	D03 Non-coincident Peak Demand
18	590 MT Super & Engineering	D = Distribution	Demand/Customer from Other Dist Mt Exp	S17 Sum of Other Distribution Maintenance Expenses
19	591 MT of Structures	D = Distribution	Demand	S08 Sum of Account 361 Structures & Improvements
20	592 MT of Station Equipment	D = Distribution	Demand	S09 Sum of Account 362 Station Equipment
21	593 MT of Overhead Lines	D = Distribution	Demand	S10 Sum of Accounts 364 and 365 Poles, Towers, Fixtures & Overhead Conductors
22	594 MT of Underground Lines	D = Distribution	Demand	S11 Sum of Accounts 366 and 367 Underground Conduit & Underground Conductors
23	595 MT of Line Transformers	D = Distribution	Demand	S12 Sum of Account 368 Line Transformers
24	596 MT of Street Lights	D = Distribution	Customer	S15 Sum of Account 373 Street Light and Signal Systems
25	597 MT of Meters	D = Distribution	Customer	S14 Sum of Account 370 Meters
26	598 Misc Maintenance Expense	D = Distribution	Demand/Customer from Other Dist Mt Exp	S17 Sum of Other Distribution Maintenance Expenses
	Customer Accounts Expense			
27	901 Supervision	C = Customer Relations	Customer	S18 Sum of Other Customer Accounts Expenses Excluding Uncollectibles
28	902 Meter Reading	C = Customer Relations	Customer	C03 Customers Weighted by Estimated Meter Reading Time
29	903 Customer Records & Collections	C = Customer Relations	Customer	C01/C06 All Customers unweighted / Direct Assign Handbilled Cust
30	904 Uncollectible Accounts	R = Revenue Conversion	Revenue	R01 Retail Sales Revenue
31	905 Misc Cust Accounts	C = Customer Relations	Customer	C01 All Customers unweighted
	Customer Service & Info Expense			
32	907 Supervision	C = Customer Relations	Customer	C01 All Customers unweighted
33	908 Customer Assistance	C = Customer Relations	Customer	C01 All Customers unweighted
34	908 DSM Amortization Expenses	DSM	Demand/Energy from Production Plant	S01 Sum of Production Plant
35	909 Advertising	C = Customer Relations	Customer	C01 All Customers unweighted
36	910 Misc Cust Service & Info	C = Customer Relations	Customer	C01 All Customers unweighted
	Sales Expenses			
37	911 - 916	C = Customer Relations	Energy	E02 Annual Generation Level Consumption

IPUC Case No. AVU-E-11-01 Methodology Matrix
Avista Utilities Idaho Jurisdiction
Electric Cost of Service Methodology

Line	Account	Functional Category	Classification	Allocation
	Admin & General Expenses			
1	920 - 927 & 930 -935 Assigned to Production	P = Production	Demand/Energy from Production Plant	S01 Sum of Production Plant
2	920 - 927 & 930 -935 Assigned to Transmission	T = Transmission	Demand/Energy from Transmission Plant	S02 Sum of Transmission Plant
3	920 - 927 & 930 - 935 Assigned to Distribution	D = Distribution	Demand/Customer from Distribution Plant	S03 Sum of Distribution Plant
4	920 - 927 & 930 - 935 Assigned to Customer Relations	C = Customer Relations	Customer	C01 All Customers unweighted
5	920 - 935 Assigned to Other	O=Other	Demand/Energy/Customer by Corp Cost Allocator	S23 25% direct O&M, 25% direct labor, 25% net direct plant, 25% number of customers
6	928 FERC Commission Fees	P = Production	Demand/Energy from Production Plant	S01 Sum of Production Plant
7	928 IPUC Commission Fees	R = Revenue Conversion	Revenue	R01 Retail Sales Revenue
	Depreciation & Amortization Expens			
8	Intangible	P/T/O	Demand/Energy/Customer as in related Plant	S01/S02/S23 Sum of Production Plant / Sum of Transmission Plant / Corp Cost Alloctor
9	Production	P = Production	Demand/Energy by Load Factor Peak Credit	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
10	Transmission	T = Transmission	Demand	D02 Weighted 12 Month Coincident Peak Demand (Excess Peak Percentage)
11	Distribution	D = Distribution	Demand/Customer as in related Plant	D03/D04/D05/D06/D07/D08/C02/C04/C05 - See Related Plant
12	General	O=Other	Demand/Energy/Customer by Corp Cost Allocator	S23 25% direct O&M, 25% direct labor, 25% net direct plant, 25% number of customers
	Taxes			
13	Property Tax	P/T/D/O	Demand/Energy/Customer from Related Plant	S01/S02/S03/S04 Sums of Production / Transmission / Distribution / General Plant
14	State kWh Generation Taxes	P = Production	Demand/Energy by Load Factor Peak Credit	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
15	Misc Production Taxes	P = Production	Demand/Energy by Load Factor Peak Credit	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
16	Misc Distribution Taxes	D = Distribution	Demand/Customer from Distribution Plant	S03 Sum of Distribution Plant
17	Idaho State Income Tax	R = Revenue Conversion	Revenue	R03 Revenue less Expenses Before Income Taxes less Interest Expense
18	Federal Income Tax	R = Revenue Conversion	Revenue	R03 Revenue less Expenses Before Income Taxes less Interest Expense
19	Deferred FIT	R = Revenue Conversion	Revenue	R03 Revenue less Expenses Before Income Taxes less Interest Expense
	Other Income Related Item:			
20	CS2 Levelized Return and Boulder Write-off Amort.	P = Production	Demand/Energy by Load Factor Peak Credit	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
	Operating Revenue:			
21	Sales of Electricity- Retail	R = Revenue from Rates	Revenue	Input Pro Forma Revenue per Revenue Study
22	Sales for Resale (447)	P = Production	Demand/Energy from Production Plant	S01 Sum of Production Plant
23	Misc Service Revenue (451)	D = Distribution	Demand/Customer from Distribution Plant	S03 Sum of Distribution Plant
24	Sales of Water & Water Power (453)	P = Production	Demand/Energy from Production Plant	S01 Sum of Production Plant
25	Rent from Production Property (454)	P = Production	Demand/Energy from Production Plant	S01 Sum of Production Plant
26	Rent from Transmission Property (454)	T = Transmission	Demand/Energy from Transmission Plant	S02 Sum of Transmission Plant
27	Rent from Distribution Property (454)	D = Distribution	Demand/Customer from Distribution Plant	S03 Sum of Distribution Plant
28	Other Electric Revenues - Generation (456)	P = Production	Demand/Energy from Production Plant	S01 Sum of Production Plant
29	Other Electric Revenues - Wheeling (456)	T = Transmission	Demand/Energy from Transmission Plant	S02 Sum of Transmission Plant
30	Other Electric Revenues - Energy Delivery (456)	D = Distribution	Demand/Customer from Distribution Plant	S03 Sum of Distribution Plant
	Salaries & Wages (allocation factor input			
	Operation & Maintenance Expenses			
31	Production Total	P = Production	Demand/Energy from Production Plant	S01 Sum of Production Plant
32	Transmission Total	T = Transmission	Demand/Energy from Transmission Plant	S02 Sum of Transmission Plant
33	Distribution Total	D = Distribution	Demand/Customer from Distribution Plant	S03 Sum of Distribution Plant
34	Customer Accounts Total	C = Customer Relations	Customer	S18 Sum of Other Customer Accounts Expenses Excluding Uncollectibles
35	Customer Service Total	C = Customer Relations	Customer	C01 All Customers unweighted
36	Sales Total	C = Customer Relations	Energy	E02 Annual Generation Level Consumption
37	Admin & General Total	O=Other	Energy/Customer by Corp Cost Allocator	S23 25% direct O&M, 25% direct labor, 25% net direct plant, 25% number of customers

Sumcost
Scenario: Company Base Case
AVU-E-11-01 Proposed Method
Prod by LF PC & Trans By Demand W12 CP

AVISTA UTILITIES
Cost of Service Basic Summary
For the Twelve Months Ended December 31, 2010

Idaho Jurisdiction
Electric Utility

06-15-11

	(b)	(c) (d) (e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
				Residential	General	Large Gen	Extra Large	Extra Large	Pumping	Street &
			System	Service	Service	Service	Gen Service	Service CP	Service	Area Lights
	Description		Total	Sch 1	Sch 11-12	Sch 21-22	Sch 25	Sch 25P	Sch 31-32	Sch 41-49
	Plant In Service									
1	Production Plant		391,411,000	145,064,243	36,927,840	78,806,700	29,717,500	93,659,118	5,883,417	1,352,181
2	Transmission Plant		184,064,000	79,659,536	17,814,655	34,126,837	12,717,014	37,087,424	2,134,684	523,851
3	Distribution Plant		440,482,000	221,637,409	60,593,493	110,013,429	10,501,372	2,220,959	15,074,108	20,441,230
4	Intangible Plant		50,759,000	21,983,423	5,339,188	9,351,787	3,192,978	9,654,515	817,015	420,094
5	General Plant		80,147,000	43,795,365	10,038,458	12,267,439	3,126,263	8,075,112	1,461,306	1,383,058
6	Total Plant In Service		1,146,863,000	512,139,975	130,713,634	244,566,191	59,255,127	150,697,128	25,370,530	24,120,414
	Accum Depreciation									
7	Production Plant		(166,852,000)	(61,838,474)	(15,741,724)	(33,593,986)	(12,668,076)	(39,925,325)	(2,508,003)	(576,412)
8	Transmission Plant		(63,228,000)	(27,363,923)	(6,119,529)	(11,722,942)	(4,368,433)	(12,739,936)	(733,287)	(179,949)
9	Distribution Plant		(143,547,000)	(71,484,271)	(18,514,037)	(35,974,582)	(3,369,089)	(706,067)	(4,812,648)	(8,686,305)
10	Intangible Plant		(10,413,000)	(5,286,112)	(1,231,174)	(1,705,027)	(492,500)	(1,370,137)	(181,397)	(146,653)
11	General Plant		(29,933,000)	(16,356,528)	(3,749,125)	(4,581,597)	(1,167,585)	(3,015,862)	(545,763)	(516,539)
12	Total Accumulated Depreciation		(413,973,000)	(182,329,308)	(45,355,590)	(87,578,134)	(22,065,683)	(57,757,327)	(8,781,099)	(10,105,859)
13	Net Plant		732,890,000	329,810,667	85,358,044	156,988,058	37,189,443	92,939,801	16,589,431	14,014,556
14	Accumulated Deferred FIT		(114,339,000)	(51,142,446)	(12,995,780)	(24,091,553)	(5,957,508)	(15,350,408)	(2,484,578)	(2,316,728)
15	Miscellaneous Rate Base		8,450,000	3,337,688	896,214	1,966,304	515,668	1,374,473	187,425	172,229
16	Total Rate Base		627,001,000	282,005,909	73,258,479	134,862,809	31,747,603	78,963,866	14,292,278	11,870,057
17	Revenue From Retail Rates		246,379,000	100,409,000	30,018,000	51,853,000	14,027,000	42,128,000	4,599,000	3,345,000
18	Other Operating Revenues		20,603,000	8,099,885	2,028,573	4,173,542	1,447,568	4,378,837	330,481	144,114
19	Total Revenues		266,982,000	108,508,885	32,046,573	56,026,542	15,474,568	46,506,837	4,929,481	3,489,114
	Operating Expenses									
20	Production Expenses		114,095,000	42,285,743	10,764,342	22,971,890	8,662,552	27,301,320	1,714,997	394,156
21	Transmission Expenses		10,627,000	4,599,171	1,028,535	1,970,325	734,221	2,141,256	123,247	30,245
22	Distribution Expenses		10,241,000	4,863,111	1,322,689	2,483,533	284,251	85,895	333,212	868,308
23	Customer Accounting Expenses		3,722,000	2,856,699	572,227	124,044	45,399	72,043	43,221	8,368
24	Customer Information Expenses		531,000	434,087	84,326	6,259	35	4	5,751	539
25	Sales Expenses		18,000	6,243	1,670	3,683	1,415	4,621	293	75
26	Admin & General Expenses		21,915,000	11,645,885	2,712,434	3,529,446	898,767	2,338,996	408,648	380,823
27	Total O&M Expenses		161,149,000	66,690,939	16,486,223	31,089,181	10,626,640	31,944,135	2,629,368	1,682,514
28	Taxes Other Than Income Taxes		8,715,000	3,694,921	942,886	1,844,164	510,968	1,404,462	175,820	141,778
29	Other Income Related Items		238,000	88,207	22,454	47,919	18,070	56,950	3,577	822
	Depreciation Expense									
30	Production Plant Depreciation		10,283,000	3,811,072	970,154	2,070,379	780,727	2,460,577	154,567	35,524
31	Transmission Plant Depreciation		3,770,000	1,631,587	364,880	698,986	260,470	759,625	43,723	10,730
32	Distribution Plant Depreciation		11,935,000	5,875,355	1,624,697	3,178,847	325,280	51,534	425,451	453,835
33	General Plant Depreciation		6,425,000	3,510,864	804,735	983,422	250,617	647,343	117,146	110,873
34	Amortization Expense		1,054,000	392,932	99,530	211,623	79,771	250,809	15,716	3,619
35	Total Depreciation Expense		33,467,000	15,221,811	3,863,996	7,143,257	1,696,866	4,169,888	756,602	614,581
36	Income Tax		15,927,000	5,119,437	3,050,422	4,235,905	595,595	2,344,306	333,915	247,421
37	Total Operating Expenses		219,496,000	90,815,314	24,365,982	44,360,426	13,448,138	39,919,741	3,899,283	2,687,116
38	Net Income		47,486,000	17,693,571	7,680,592	11,666,116	2,026,429	6,587,096	1,030,198	801,998
39	Rate of Return		7.57%	6.27%	10.48%	8.65%	6.38%	8.34%	7.21%	6.76%
40	Return Ratio		1.00	0.83	1.38	1.14	0.84	1.10	0.95	0.89
41	Interest Expense		18,935,000	8,516,385	2,212,356	4,072,764	958,756	2,384,655	431,617	358,468

Sumcost
Scenario: Company Base Case
AVU-E-11-01 Proposed Method
Prod by LF PC & Trans By Demand W12 CP

AVISTA UTILITIES
Revenue to Cost by Functional Component Summary
For the Twelve Months Ended December 31, 2010

Idaho Jurisdiction
Electric Utility

06-15-11

	(b) Description	(c) (d) (e)	(f) System Total	(g) Residential Service Sch 1	(h) General Service Sch 11-12	(i) Large Gen Service Sch 21-22	(j) Extra Large Gen Service Sch 25	(k) Extra Large Service CP Sch 25P	(l) Pumping Service Sch 31-32	(m) Street & Area Lights Sch 41-49
	Functional Cost Components at Current Return by Schedule									
1	Production		138,711,985	49,691,178	13,970,021	28,585,483	10,207,062	33,727,506	2,062,011	468,724
2	Transmission		23,000,162	9,046,463	2,688,413	4,594,919	1,456,464	4,892,063	260,108	61,732
3	Distribution		53,896,661	25,457,038	9,191,343	13,746,595	1,190,148	304,966	1,716,155	2,290,416
4	Common		30,770,193	16,214,321	4,168,223	4,926,003	1,173,326	3,203,464	560,726	524,129
5	Total Current Rate Revenue		246,379,000	100,409,000	30,018,000	51,853,000	14,027,000	42,128,000	4,599,000	3,345,000
	Expressed as $/kWh									
6	Production		$0.04130	$0.04324	$0.04546	$0.04207	$0.03841	$0.03792	$0.03823	$0.03391
7	Transmission		$0.00685	$0.00787	$0.00875	$0.00676	$0.00548	$0.00550	$0.00482	$0.00447
8	Distribution		$0.01605	$0.02215	$0.02991	$0.02023	$0.00448	$0.00034	$0.03182	$0.16571
9	Common		$0.00916	$0.01411	$0.01356	$0.00725	$0.00442	$0.00360	$0.01040	$0.03792
10	Total Current Melded Rates		$0.07335	$0.08737	$0.09768	$0.07631	$0.05279	$0.04736	$0.08527	$0.24200
	Functional Cost Components at Uniform Current Return									
11	Production		138,396,052	51,292,167	13,057,035	27,864,664	10,507,586	33,116,218	2,080,273	478,107
12	Transmission		23,024,572	9,964,614	2,228,436	4,268,927	1,590,772	4,639,267	267,028	65,529
13	Distribution		54,062,933	28,076,744	7,537,586	12,671,480	1,304,906	289,050	1,766,763	2,416,405
14	Common		30,895,443	16,804,253	3,861,110	4,777,380	1,214,690	3,134,828	566,594	536,587
15	Total Uniform Current Cost		246,379,000	106,137,779	26,684,168	49,582,452	14,617,953	41,179,363	4,680,658	3,496,627
	Expressed as $/kWh									
16	Production		$0.04120	$0.04463	$0.04249	$0.04101	$0.03954	$0.03723	$0.03857	$0.03459
17	Transmission		$0.00685	$0.00867	$0.00725	$0.00628	$0.00599	$0.00522	$0.00495	$0.00474
18	Distribution		$0.01610	$0.02443	$0.02453	$0.01865	$0.00491	$0.00032	$0.03276	$0.17482
19	Common		$0.00920	$0.01462	$0.01256	$0.00703	$0.00457	$0.00352	$0.01050	$0.03882
20	Total Current Uniform Melded Rates		$0.07335	$0.09236	$0.08683	$0.07297	$0.05501	$0.04630	$0.08678	$0.25297
21	**Revenue to Cost Ratio at Current Rates**		1.00	0.95	1.12	1.05	0.96	1.02	0.98	0.96
	Functional Cost Components at Proposed Return by Schedule									
22	Production		141,940,496	50,716,869	14,270,729	29,186,793	10,467,952	34,722,455	2,099,362	476,336
23	Transmission		24,556,998	9,634,635	2,839,902	4,866,841	1,573,050	5,303,498	274,259	64,812
24	Distribution		57,347,513	27,135,233	9,735,994	14,643,384	1,289,764	330,870	1,819,651	2,392,616
25	Common		31,542,993	16,592,262	4,269,375	5,049,982	1,209,234	3,315,177	572,727	534,235
26	Total Proposed Rate Revenue		255,388,000	104,079,000	31,116,000	53,747,000	14,540,000	43,672,000	4,766,000	3,468,000
	Expressed as $/kWh									
27	Production		$0.04226	$0.04413	$0.04644	$0.04295	$0.03939	$0.03904	$0.03892	$0.03446
28	Transmission		$0.00731	$0.00838	$0.00924	$0.00716	$0.00592	$0.00596	$0.00508	$0.00469
29	Distribution		$0.01707	$0.02361	$0.03168	$0.02155	$0.00485	$0.00037	$0.03374	$0.17310
30	Common		$0.00939	$0.01444	$0.01389	$0.00743	$0.00455	$0.00373	$0.01062	$0.03865
31	Total Proposed Melded Rates		$0.07603	$0.09057	$0.10125	$0.07910	$0.05472	$0.04910	$0.08836	$0.25090
	Functional Cost Components at Uniform Requested Return									
32	Production		141,451,580	52,424,603	13,345,311	28,479,865	10,739,574	33,847,363	2,126,202	488,663
33	Transmission		24,525,072	10,614,003	2,373,662	4,547,131	1,694,441	4,941,606	284,430	69,799
34	Distribution		57,732,025	29,929,606	8,059,717	13,588,986	1,393,486	308,085	1,894,030	2,558,115
35	Common		31,679,323	17,221,528	3,958,080	4,904,223	1,246,620	3,216,920	581,351	550,601
36	Total Uniform Cost		255,388,000	110,189,739	27,736,769	51,520,205	15,074,121	42,313,975	4,886,013	3,667,178
	Expressed as $/kWh									
37	Production		$0.04211	$0.04562	$0.04343	$0.04191	$0.04041	$0.03805	$0.03942	$0.03535
38	Transmission		$0.00730	$0.00924	$0.00772	$0.00669	$0.00638	$0.00556	$0.00527	$0.00505
39	Distribution		$0.01719	$0.02604	$0.02623	$0.02000	$0.00524	$0.00035	$0.03512	$0.18507
40	Common		$0.00943	$0.01499	$0.01288	$0.00722	$0.00469	$0.00362	$0.01078	$0.03983
41	Total Uniform Melded Rates		$0.07603	$0.09589	$0.09025	$0.07582	$0.05673	$0.04757	$0.09059	$0.26531
42	**Revenue to Cost Ratio at Proposed Rates**		1.00	0.94	1.12	1.04	0.96	1.03	0.98	0.95
43	**Current Revenue to Proposed Cost Ratio**		**0.96**	**0.91**	**1.08**	**1.01**	**0.93**	**1.00**	**0.94**	**0.91**
44	**Target Revenue Increase**		**9,009,000**	**9,781,000**	**(2,281,000)**	**(333,000)**	**1,047,000**	**186,000**	**287,000**	**322,000**

Sumcost
Scenario: Company Base Case
AVU-E-11-01 Proposed Method
Prod by LF PC & Trans By Demand W12 CP

AVISTA UTILITIES
Revenue to Cost By Classification Summary
For the Twelve Months Ended December 31, 2010

Idaho Jurisdiction
Electric Utility

06-15-11

	(b)	(c) (d) (e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
	Description		System Total	Residential Service Sch 1	General Service Sch 11-12	Large Gen Service Sch 21-22	Extra Large Gen Service Sch 25	Extra Large Service Potlatch Sch 25P	Pumping Service Sch 31-32	Street & Area Lights Sch 41-49
	Cost Classifications at Current Return by Schedule									
1	Energy		94,714,876	31,711,603	9,376,466	19,824,937	7,205,637	24,686,946	1,523,248	386,038
2	Demand		127,473,558	52,209,821	15,922,721	31,239,225	6,778,357	17,434,969	2,730,654	1,157,811
3	Customer		24,190,566	16,487,575	4,718,813	788,838	43,005	6,086	345,098	1,801,151
4	Total Current Rate Revenue		246,379,000	100,409,000	30,018,000	51,853,000	14,027,000	42,128,000	4,599,000	3,345,000
	Expressed as Unit Cost									
5	Energy	$/kWh	$0.02820	$0.02760	$0.03051	$0.02918	$0.02712	$0.02776	$0.02824	$0.02793
6	Demand	$/kW/mo	$17.46	$19.22	$21.74	$17.83	$14.03	$12.84	$12.50	$27.97
7	Customer	$/Cust/mo	$16.46	$13.72	$20.21	$45.53	$447.97	$507.14	$21.67	$1,208.02
	Cost Classifications at Uniform Current Return									
8	Energy		94,407,441	32,745,695	8,756,967	19,319,309	7,420,355	24,234,357	1,536,899	393,859
9	Demand		127,413,173	55,967,498	13,807,180	29,531,685	7,153,076	16,939,069	2,791,199	1,223,465
10	Customer		24,558,386	17,424,586	4,120,021	731,458	44,521	5,938	352,560	1,879,303
11	Total Uniform Current Cost		246,379,000	106,137,779	26,684,168	49,582,452	14,617,953	41,179,363	4,680,658	3,496,627
	Expressed as Unit Cost									
12	Energy	$/kWh	$0.02811	$0.02849	$0.02849	$0.02843	$0.02792	$0.02725	$0.02849	$0.02849
13	Demand	$/kW/mo	$17.45	$20.60	$18.85	$16.86	$14.81	$12.48	$12.78	$29.55
14	Customer	$/Cust/mo	$16.71	$14.50	$17.65	$42.21	$463.76	$494.82	$22.14	$1,260.43
15	**Revenue to Cost Ratio at Current Rates**		1.00	0.95	1.12	1.05	0.96	1.02	0.98	0.96
	Cost Classifications at Proposed Return by Schedule									
16	Energy		96,960,526	32,374,105	9,580,509	20,246,734	7,392,037	25,423,591	1,551,167	392,383
17	Demand		133,311,347	54,617,047	16,619,467	32,663,565	7,103,641	18,242,082	2,854,475	1,211,069
18	Customer		25,116,127	17,087,848	4,916,024	836,701	44,321	6,326	360,359	1,864,548
19	Total Proposed Rate Revenue		255,388,000	104,079,000	31,116,000	53,747,000	14,540,000	43,672,000	4,766,000	3,468,000
	Expressed as Unit Cost									
20	Energy	$/kWh	$0.02887	$0.02817	$0.03117	$0.02980	$0.02782	$0.02858	$0.02876	$0.02839
21	Demand	$/kW/mo	$18.26	$20.10	$22.69	$18.65	$14.70	$13.44	$13.07	$29.25
22	Customer	$/Cust/mo	$17.08	$14.22	$21.06	$48.29	$461.68	$527.19	$22.63	$1,250.54
	Cost Classifications at Uniform Requested Return									
23	Energy		96,516,243	33,477,144	8,952,573	19,750,849	7,586,105	24,775,685	1,571,229	402,657
24	Demand		133,304,580	58,625,264	14,475,118	30,988,930	7,442,324	17,532,175	2,943,458	1,297,312
25	Customer		25,567,177	18,087,332	4,309,077	780,426	45,692	6,115	371,326	1,967,209
26	Total Uniform Cost		255,388,000	110,189,739	27,736,769	51,520,205	15,074,121	42,313,975	4,886,013	3,667,178
	Expressed as Unit Cost									
27	Energy	$/kWh	$0.02873	$0.02913	$0.02913	$0.02907	$0.02855	$0.02786	$0.02913	$0.02913
28	Demand	$/kW/mo	$18.26	$21.58	$19.76	$17.69	$15.40	$12.92	$13.47	$31.34
29	Customer	$/Cust/mo	$17.39	$15.05	$18.46	$45.04	$475.95	$509.55	$23.32	$1,319.39
30	**Revenue to Cost Ratio at Proposed Rates**		1.00	0.94	1.12	1.04	0.96	1.03	0.98	0.95
31	**Current Revenue to Proposed Cost Ratio**		**0.96**	**0.91**	**1.08**	**1.01**	**0.93**	**1.00**	**0.94**	**0.91**
32	Annual Consumption (mWh's)		3,358,927	1,149,177	307,317	679,496	265,733	889,447	53,936	13,822
33	Monthly Average NCP Demand (kW)		608,472	226,417	61,038	145,985	40,262	113,115	18,205	3,450
34	Monthly Average Number of Customers		122,507	100,148	19,455	1,444	8	1	1,327	124

Exhibit No. 12
Case No. AVU-E-11-01
T. Knox, Avista
Schedule 3, p. 3 of 4

Sumcost | AVISTA UTILITIES | Idaho Jurisdiction
Scenario: Company Base Case | Customer Cost Analysis | Electric Utility | 06-15-11
AVU-E-11-01 Proposed Method | For the Twelve Months Ended December 31, 2010
Prod by LF PC & Trans By Demand W12 CP

Meter, Services, Meter Reading & Billing Costs by Schedule at Requested Rate of Return

	(b) Description	(c) (d) (e)	(f) System Total	(g) Residential Service Sch 1	(h) General Service Sch 11-12	(i) Large Gen Service Sch 21-22	(j) Extra Large Gen Service Sch 25	(k) Extra Large Service CP Sch 25P	(l) Pumping Service Sch 31-32	(m) Street & Area Lights Sch 41-49
	Rate Base									
1	Services		44,540,000	36,458,642	7,082,504	515,824	0	0	483,030	0
2	Services Accum. Depr.		(16,606,000)	(13,593,000)	(2,640,594)	(192,317)	0	0	(180,090)	0
3	Total Services		27,934,000	22,865,642	4,441,910	323,508	0	0	302,940	0
4	Meters		28,803,000	16,321,800	7,990,151	3,391,026	74,135	11,710	1,014,178	0
5	Meters Accum. Depr.		(2,142,000)	(1,213,807)	(594,206)	(252,181)	(5,513)	(871)	(75,422)	0
6	Total Meters		26,661,000	15,107,993	7,395,945	3,138,845	68,622	10,839	938,757	0
7	Total Rate Base		54,595,000	37,973,635	11,837,855	3,462,353	68,622	10,839	1,241,697	0
8	Return on Rate Base @ 8.49%		4,635,169	3,223,999	1,005,046	293,957	5,826	920	105,421	0
9	Revenue Conversion Factor		0.63778	0.63778	0.63778	0.63778	0.63778	0.63778	0.63778	0.63778
10	**Rate Base Revenue Requirement**		**7,267,639**	**5,055,017**	**1,575,845**	**460,905**	**9,135**	**1,443**	**165,294**	**0**
	Expenses									
11	Services Depr Exp		725,000	593,456	115,285	8,396	0	0	7,863	0
12	Meters Depr Exp		686,000	388,736	190,301	80,764	1,766	279	24,155	0
13	Services Operations Exp		415,000	339,702	65,991	4,806	0	0	4,501	0
14	Meters Operating Exp		234,000	132,601	64,913	27,549	602	95	8,239	0
15	Meters Maintenance Exp		26,000	14,733	7,213	3,061	67	11	915	0
16	Meter Reading		454,000	354,576	68,880	5,112	18,430	2,304	4,698	0
17	Billing		2,606,000	2,128,245	413,436	30,685	2,486	311	28,196	2,640
18	Total Expenses		5,146,000	3,952,049	926,020	160,374	23,352	2,999	78,567	2,640
19	Revenue Conversion Factor		0.996296	0.996296	0.996296	0.996296	0.996296	0.996296	0.996296	0.996296
20	**Expense Revenue Requirement**		**5,165,132**	**3,966,742**	**929,462**	**160,970**	**23,439**	**3,010**	**78,859**	**2,650**
21	**Total Meter, Service, Meter Reading, and**		**12,432,770**	**9,021,759**	**2,505,307**	**621,875**	**32,573**	**4,453**	**244,152**	**2,650**
22	Total Customer Bills		1,470,085	1,201,778	233,459	17,327	96	12	15,922	1,491
23	**Average Unit Cost per Month**		**$8.46**	**$7.51**	**$10.73**	**$35.89**	**$339.31**	**$371.10**	**$15.33**	**$1.78**

Distribution Fixed Costs per Customer

	Description	System Total	Residential Service Sch 1	General Service Sch 11-12	Large Gen Service Sch 21-22	Extra Large Gen Service Sch 25	Extra Large Service CP Sch 25P	Pumping Service Sch 31-32	Street & Area Lights Sch 41-49
24	Total Customer Related Cost	25,567,177	18,087,332	4,309,077	780,426	45,692	6,115	371,326	1,967,209
25	Customer Related Unit Cost per Month	$17.39	$15.05	$18.46	$45.04	$475.95	$509.55	$23.32	$1,319.39
26	Total Distribution Demand Related Cost	49,476,832	23,465,005	6,328,510	14,804,775	1,541,039	340,646	1,892,713	1,104,143
27	Dist Demand Related Unit Cost per Month	$33.66	$19.53	$27.11	$854.43	$16,052.49	$28,387.19	$118.87	$740.54
28	**Total Distribution Unit Cost per Month**	**$51.05**	**$34.58**	**$45.57**	**$899.47**	**$16,528.45**	**$28,896.75**	**$142.20**	**$2,059.93**

Avista Utilities

Cost of Service Workshop

February 8, 2011 IPUC Workshop

Workshop Topics

Item # 1 – Peak Credit Classification Method

Item # 2 – Allocation of Transmission Costs

Item #1 - Peak Credit Classification Method

1. Review Previous Peak Credit Methodology
2. Proposed Peak Credit Methodology
3. Why it is preferable from Avista's viewpoint
4. Is the Proposed Peak Credit Methodology stable over time?

AVISTA

Item #1 - Peak Credit Classification Method (continued)

Traditionally, both production and transmission costs have been classified into energy-related and demand-related components by the peak credit ratio method.

In prior cost of service studies, Avista's electric system resource costs were classified to energy and demand using a comparison of the replacement cost-per-kW of the Company's peaking units, to the replacement cost-per-kW of the Company's thermal and hydro plants (separately).

- Created separate peak credit ratios applied to thermal plant and hydro plant
- Transmission costs were assigned to energy and demand by a 50/50 weighting of the thermal and hydro peak credit ratios.
- Fuel and load dispatching expenses were classified entirely to energy
- Peaking plant related costs were classified entirely to demand.

Item #1 - Peak Credit Classification Method (continued)

Proposed Methodology - link the classification methodology to the Integrated Resource Plan (IRP).

- The IRP process is an exercise to meet customer load growth in a least-cost fashion. Central to the equation is the level of our customers' coincident peak demand.
- Use the incremental capacity resource from our latest IRP—a gas-fired CCCT.
- Using IRP models, the Company calculated the costs of capacity and energy from this resource, and used that figure to allocate overall production costs.

AVISTA

Item #1 - Peak Credit Classification Method (continued)

For the IRP the Company models the Western Interconnect wholesale power marketplace using AURORA$_{xmp}$.

- AURORA$_{xmp}$ dispatches available resources against electricity loads on an hourly basis.
- The IRP uses AURORA$_{xmp}$ to look at costs out 20 years and "mark-to-market" (MTM) each potential resource option reasonably available to the Company in the future.
- The dispatched value of the CCCT (i.e., market sales price less fuel and variable maintenance and operation costs) is tracked hourly over the 20-year IRP timeframe.
- Additionally, for the IRP the Company models the 20-year future over 250 to 500 Monte Carlo iterations to reflect volatility created by various factors including natural gas prices, load variability and forced outage rates.

Item #1 - Peak Credit Classification Method (continued)

For each of the 20 years evaluated for the IRP there are 250 to 500 MTM values for the CCCT.

- The annual average MTM figures represent the energy value generated by the plant.
- Remaining costs not recovered in the wholesale marketplace are defined as capacity.

The ratio of those costs remaining after dispatch into the wholesale marketplace (MTM values) relative to the entire cost of the CCCT plant equals the share of production costs then attributable to demand in the cost of service models.

Item #1 - Peak Credit Classification Method (continued)

Net effect - increases the overall production costs that are classified as demand-related.

- Using the prior method, (with the Settlement power supply costs) approximately 27% of total production costs were classified as demand-related
- 41% of total production costs would be classified as demand-related under the revised method

AVISTA

Item #1 - Peak Credit Classification Method (continued)

Why is this methodology preferable?

- Tied to the Company's IRP
- Market based modeling represents how the system is actually used vs historical replacement cost analysis entirely based on vintage investments
- Less complicated single ratio applied to all production costs vs multiple ratios applied dependent on each cost item's relationship to plant investment
- Overall weighted demand/energy relationship stays the same when power costs are updated – not impacted by swings in the cost of fuel

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Item #1 - Peak Credit Classification Method (continued)

Will the new methodology provide a "stable" demand/energy classification over time?

- We believe it will be more consistent over time than the present method.
  - 2007 IRP Result – 40.9% Demand
  - 2009 IRP Result – 40.6% Demand
  - 2011 Draft IRP Result – 46.8% Demand
- Present method overall assignment results vary from 23% to 34% Demand depending on the cost of fuel and shifting proportionate replacement costs

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Item #2 – Allocation of Transmission Costs

Historically, transmission costs were included in the production peak credit classification

- 50/50 weighting of thermal and hydro peak credit ratios applied to all transmission costs
- Transmission system considered extension of generation facilities
- Demand classified portion allocated to customer classes by 12 CP (average of the 12 monthly system coincident peak hours)

Item #2 – Allocation of Transmission Costs (continued)

In AVU-E-10-01, Avista proposed to change methodologies and classified transmission costs as 100% demand.

- Consistent with traditional NARUC approach (100% Demand-related)
- Proposed 7 CP (four winter, three summer monthly system coincident peak hours)
  - Based on the rationale that lower customer demands in the off-peak fall and spring seasons do not impose the same capacity utilization of transmission facilities as the higher demand winter and summer months
- Settlement approved transmission classification – 100% demand, but used 12 CP allocation and set up this workshop to discuss alternatives

Item #2 – Allocation of Transmission Costs (continued)

Workshop Discussion – "consideration of the use of a 12 CP (whether "weighted" or not) versus a 7 CP or other method for allocating transmission costs.

1. 12 CP (average of the monthly system coincident peaks)
   - Captures relative contribution to demand throughout the year
   - Aligns with FERC Open Access transmission cost methodology
2. Weighted 12 CP - see Handout
   - Weighted by Relative Monthly Planning Peaks
3. 7 CP (average of 4 winter and 3 summer monthly system coincident peaks)
   - Assumes no transmission demand cost in shoulder months
4. Other

Combined-Cycle Combustion Turbine (from 2009 IRP)

Project Size	250 MW		Discount Rate	7.08%
Capital Cost	1,617 $/kW (2010)		Fixed O&M Inflation	2.6% annually
Transmission Cost	- $/kW (2010)		Variable O&M Inflation	1.9% annually
Total Capital Cost	**1,617 $/kW (2010)**			
Fixed O&M	42.64 $/kW-yr (2010)			
Variable O&M	3.38 $/MWh			

Column No	1	2	3	4	5	6		7	8	9	10	11	12	13	14	15	16
Note			from 2009 IRP	from 2009 IRP	Total Capital * Col 4	from 2009 IRP		FO&M * 250 MW	Col 3 * VO&M + Inf.	Cols 5-8	Col 9 / 250 / 1000	Col 12 / 250 / 1000	oper. margin from 2009 IRP, plus Cols 6, 8	Cols 9 + 12	(Col 10 + 11) / 250 / 1000	Cols 5 + 7	Col 13 / Col 15
		Year	Annual Generation (MWh)	Capital Recovery Factor	Capital Recovery ($mil)	Fuel ($mil)	Emissions ($mil)	Fixed O&M ($mil)	Variable O&M ($mil)	Total ($mil)	Total ($/kW-yr)	Market Value ($/kW-yr)	Market Value ($mil)	Net Value ($mil)	Net Value ($/kW-yr)	CCCT Fixed Costs ($mil)	Demand Share (%)
Levelized Cost					($46.30)	($98.17)	($31.24)	($13.62)	($6.47)	($195.80)	($783.21)	$685.88	$171.47	($24.33)	($97.32)	($59.92)	40.6%
	1	2010	1,421,996	14.6%	(58.86)	(58.89)	(0.10)	(10.66)	(4.77)	(133.28)	(533.11)	307.61	76.90	(56.38)	(225.50)	($69.52)	
	2	2011	1,432,163	15.9%	(64.17)	(60.29)	(0.10)	(10.94)	(4.90)	(140.40)	(561.61)	316.37	79.09	(61.31)	(245.24)	($75.11)	
	3	2012	1,564,110	15.3%	(61.84)	(65.56)	(4.33)	(11.22)	(5.47)	(148.43)	(593.71)	371.71	92.93	(55.50)	(222.00)	($73.06)	
	4	2013	1,624,399	14.7%	(59.60)	(70.16)	(8.10)	(11.51)	(5.80)	(155.17)	(620.66)	424.20	106.05	(49.12)	(196.46)	($71.11)	
	5	2014	1,658,096	14.2%	(57.43)	(76.05)	(11.53)	(11.81)	(6.03)	(162.86)	(651.43)	481.34	120.33	(42.52)	(170.09)	($69.24)	
	6	2015	1,665,372	13.7%	(55.34)	(85.67)	(15.69)	(12.12)	(6.18)	(175.00)	(700.00)	547.24	136.81	(38.19)	(152.76)	($67.46)	
	7	2016	1,664,088	13.2%	(53.31)	(92.91)	(21.55)	(12.43)	(6.29)	(186.48)	(745.93)	608.80	152.20	(34.28)	(137.13)	($65.74)	
	8	2017	1,646,626	12.7%	(51.34)	(97.16)	(23.00)	(12.76)	(6.33)	(190.60)	(762.40)	638.11	159.53	(31.07)	(124.29)	($64.10)	
	9	2018	1,641,165	12.2%	(49.41)	(105.91)	(32.49)	(13.09)	(6.43)	(207.33)	(829.33)	731.63	182.91	(24.42)	(97.70)	($62.50)	
	10	2019	1,596,935	11.7%	(47.48)	(111.81)	(33.93)	(13.43)	(6.37)	(213.03)	(852.11)	755.67	188.92	(24.11)	(96.44)	($60.91)	
	11	2020	1,619,380	11.3%	(45.55)	(112.08)	(36.71)	(13.78)	(6.58)	(214.71)	(858.82)	776.94	194.23	(20.47)	(81.89)	($59.33)	
	12	2021	1,642,987	10.8%	(43.63)	(110.14)	(39.91)	(14.14)	(6.80)	(214.61)	(858.45)	794.00	198.50	(16.11)	(64.45)	($57.76)	
	13	2022	1,633,936	10.3%	(41.70)	(108.96)	(42.27)	(14.50)	(6.88)	(214.31)	(857.24)	795.81	198.95	(15.36)	(61.42)	($56.20)	
	14	2023	1,645,964	9.8%	(39.77)	(114.01)	(45.22)	(14.88)	(7.06)	(220.95)	(883.79)	842.59	210.65	(10.30)	(41.20)	($54.65)	
	15	2024	1,675,118	9.4%	(37.84)	(116.58)	(49.26)	(15.27)	(7.32)	(226.28)	(905.11)	887.53	221.88	(4.39)	(17.58)	($53.11)	
	16	2025	1,660,949	8.9%	(35.92)	(122.01)	(51.70)	(15.67)	(7.39)	(232.68)	(930.73)	925.60	231.40	(1.28)	(5.13)	($51.58)	
	17	2026	1,650,350	8.4%	(33.99)	(126.23)	(55.39)	(16.07)	(7.48)	(239.16)	(956.65)	965.13	241.28	2.12	8.48	($50.06)	
	18	2027	1,656,390	7.9%	(32.06)	(126.88)	(59.82)	(16.49)	(7.65)	(242.90)	(971.60)	991.76	247.94	5.04	20.15	($48.55)	
	19	2028	1,675,123	7.5%	(30.13)	(128.94)	(64.54)	(16.92)	(7.88)	(248.42)	(993.68)	1,033.29	258.32	9.90	39.62	($47.05)	
	20	2029	1,635,914	7.0%	(28.21)	(133.50)	(67.72)	(17.36)	(7.84)	(254.63)	(1,018.52)	1,060.93	265.23	10.60	42.41	($45.57)	
	21	2030	1,635,914	6.5%	(26.46)	(133.50)	(67.72)	(17.36)	(7.84)	(252.88)	(1,011.52)	1,060.93	265.23	12.35	49.40	($43.82)	
	22	2031	1,635,914	6.2%	(25.07)	(133.50)	(67.72)	(17.36)	(7.84)	(251.49)	(1,005.97)	1,060.93	265.23	13.74	54.96	($42.43)	
	23	2032	1,635,914	5.9%	(23.86)	(133.50)	(67.72)	(17.36)	(7.84)	(250.28)	(1,001.14)	1,060.93	265.23	14.95	59.79	($41.22)	
	24	2033	1,635,914	5.6%	(22.65)	(133.50)	(67.72)	(17.36)	(7.84)	(249.08)	(996.30)	1,060.93	265.23	16.16	64.63	($40.01)	
	25	2034	1,635,914	5.3%	(21.45)	(133.50)	(67.72)	(17.36)	(7.84)	(247.87)	(991.47)	1,060.93	265.23	17.37	69.46	($38.81)	
	26	2035	1,635,914	5.0%	(20.24)	(133.50)	(67.72)	(17.36)	(7.84)	(246.66)	(986.63)	1,060.93	265.23	18.57	74.30	($37.60)	
	27	2036	1,635,914	4.7%	(19.03)	(133.50)	(67.72)	(17.36)	(7.84)	(245.45)	(981.80)	1,060.93	265.23	19.78	79.13	($36.39)	
	28	2037	1,635,914	4.4%	(17.82)	(133.50)	(67.72)	(17.36)	(7.84)	(244.24)	(976.96)	1,060.93	265.23	20.99	83.97	($35.18)	
	29	2038	1,635,914	4.1%	(16.61)	(133.50)	(67.72)	(17.36)	(7.84)	(243.03)	(972.13)	1,060.93	265.23	22.20	88.80	($33.97)	
	30	2039	1,635,914	3.8%	(15.40)	(133.50)	(67.72)	(17.36)	(7.84)	(241.82)	(967.29)	1,060.93	265.23	23.41	93.64	($32.76)	

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AVU-E-10-01 Transmission Allocation Workshop

2010 Average Annual Energy (aMW) 1,134
(From 2009 IRP)

	2010 System Demand (MW)	Excess System Demand vs. Energy aMW	Monthly Peak Weight (Monthly Excess vs. Total Excess)	Residential Sch 1	General Service Sch 11/12	Large General Service Sch 21/22	Extra Large General Service Sch 25	Extra Large General Service Sch 25P	Pumping Service Sch 31/32	Street & Area Lighting Sch 41 - 49	Total Idaho
				Total Monthly Peak Demand by Rate Schedule (kW) per AVU-E-10-01 Load Study							
January	1,779	645	12.4%	281,114	63,675	112,777	37,692	107,004	5,583	409	608,253
February	1,745	611	11.8%	212,163	51,910	106,281	35,934	105,850	5,152	0	517,289
March	1,483	348	6.7%	242,651	60,216	121,168	36,986	105,647	4,625	237	571,529
April	1,445	311	6.0%	172,403	58,667	118,333	37,487	107,782	5,405	0	500,078
May	1,389	255	4.9%	122,067	58,175	113,806	34,060	102,621	9,493	0	440,222
June	1,450	315	6.1%	153,286	43,390	103,524	36,551	106,638	14,385	0	457,774
July	1,667	533	10.3%	190,027	56,401	116,879	37,093	107,196	11,207	0	518,803
August	1,659	525	10.1%	216,550	56,660	119,097	34,795	110,248	11,725	0	549,075
September	1,359	225	4.3%	188,536	50,068	120,277	38,988	108,723	7,335	0	513,927
October	1,450	316	6.1%	215,495	42,200	106,989	36,835	108,605	9,155	0	519,278
November	1,595	461	8.9%	214,338	53,988	109,972	37,003	108,348	4,732	3,549	531,929
December	1,779	644	12.4%	282,619	61,401	114,858	39,605	100,671	3,853	3,551	606,559
		5,188	100.0%	2,491,248	656,749	1,363,961	443,029	1,279,331	92,651	7,746	6,334,716
Unweighted 12 CP Allocator				207,604	54,729	113,663	36,919	106,611	7,721	646	527,893
				39.33%	10.37%	21.53%	6.99%	20.20%	1.46%	0.12%	100.00%
Weighted 12 CP Allocator (Monthly Peak Weights)				218,685	55,760	113,440	37,003	106,438	7,386	823	539,535
				40.53%	10.33%	21.03%	6.86%	19.73%	1.37%	0.15%	100.00%
Unweighted 7 CP Allocator				230,523	57,190	115,905	37,299	106,477	7,069	600	555,062
				41.53%	10.30%	20.88%	6.72%	19.18%	1.27%	0.11%	100.00%

NATURAL GAS COST OF SERVICE STUDY

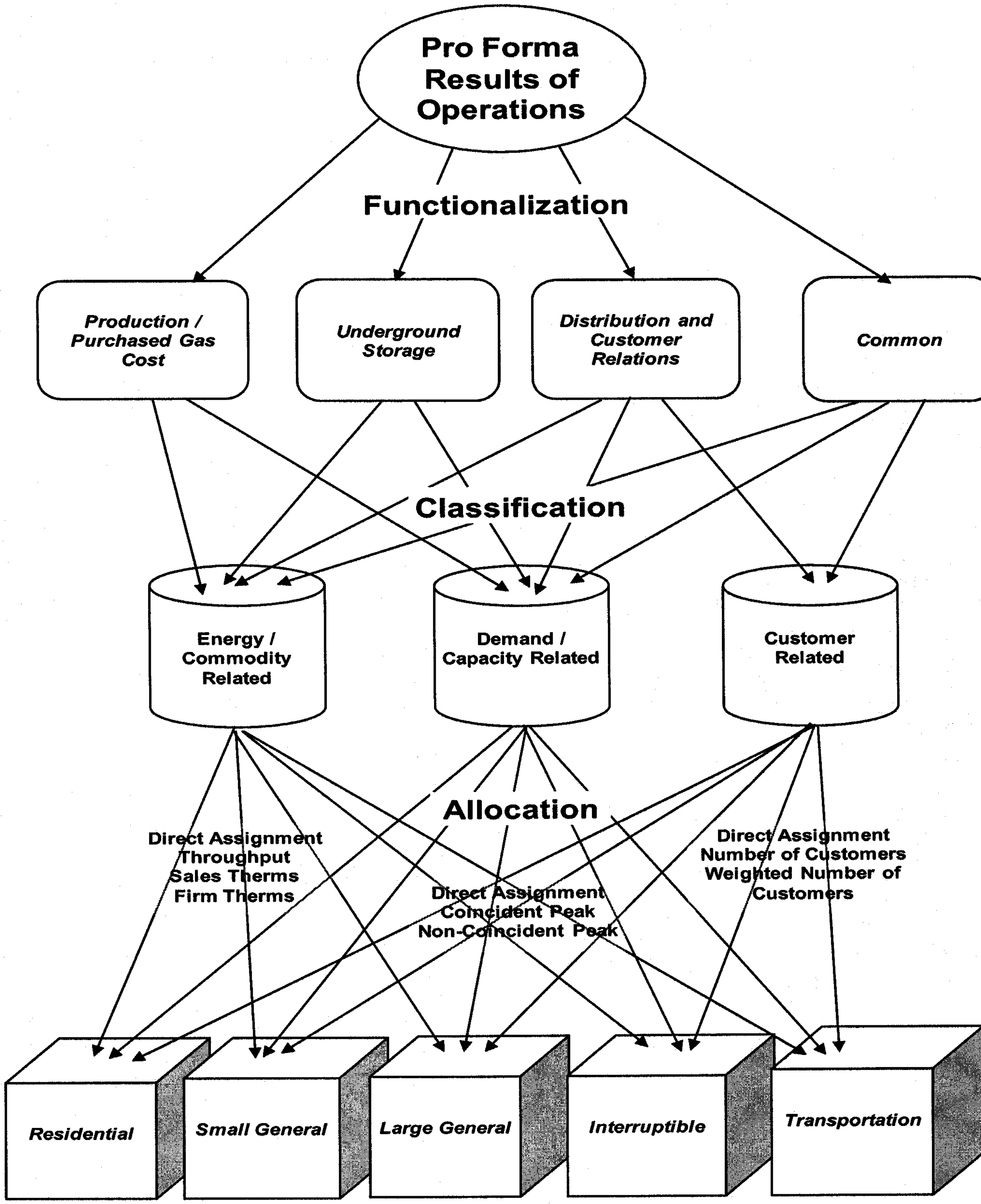
A cost of service study is an engineering-economic study, which apportions the revenue, expenses, and rate base associated with providing natural gas service to designated groups of customers. It indicates whether the revenue provided by the customers recovers the cost to serve those customers. The study results are used as a guide in determining the appropriate rate spread among the groups of customers.

There are three basic steps involved in a cost of service study: functionalization, classification, and allocation. See flow chart.

First, the expenses and rate base associated with the natural gas system under study are assigned to functional categories. The uniform system of accounts provides the basic segregation into production, underground storage, and distribution. Traditionally customer accounting, customer information, and sales expenses are included in the distribution function and administrative and general expenses and general plant rate base are allocated to all functions. In this study I have created a separate functional category for common costs. Administrative and general costs that cannot be directly assigned to the other functions have been placed in this category.

Second, the expenses and rate base items are classified into three primary cost components: Demand, commodity or customer related. Demand (capacity) related costs are allocated to rate schedules on the basis of each schedule's contribution to system peak demand. Commodity (energy) related costs are allocated based on each rate schedule's share of commodity consumption. Customer related items are allocated to rate schedules based on the number of customers within each schedule. The number of customers may be weighted by appropriate factors such as relative cost of metering equipment. In addition to these three cost components, any revenue related expense is allocated based on the proportion of revenues by rate schedule.

NATURAL GAS COST OF SERVICE STUDY FLOWCHART



Pro Forma Results of Operations by Customer Group [1]

1 Customer classes shown in this flowchart are illustrative and may not match the Company's actual rate schedules.

Exhibit No. 12
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The final step is allocation of the costs to the various rate schedules utilizing the allocation factors selected for each specific cost item. These factors are derived from usage and customer information associated with the test period results of operations.

BASE CASE COST OF SERVICE STUDY

Production - Purchased Gas Costs

The Company has no natural gas production facilities to serve its retail customers. The natural gas costs included in the production function include the cost of gas purchased to serve sales customers, pipeline transportation to get it to our system, and expenses of the gas supply department.

The demand and commodity components of account 804 have been determined directly from the weighted average cost of gas (WACOG) approved in the most recent purchased gas adjustment (PGA) filing effective November 1, 2010. The November 1, 2010 gas cost reduction to customer charges was accomplished through Schedule 155 which is excluded from base revenues. The allocation of these costs agrees with the gas costs computation used to determine pro forma results of operations.

The expenses of the gas supply department recorded in account 813 are classified as commodity related costs. The gas scheduling process includes transportation customers, so estimated scheduling dispatch labor expenses are allocated by throughput. The remaining gas supply department expenses are allocated by sales volumes.

Underground Storage

Underground storage rate base, operating and maintenance expenses are classified as commodity related and allocated to customer groups by winter throughput. This approach was proposed by commission Staff and accepted by the Idaho Public Utilities Commission in Case No. AVU-G-04-01.

Distribution Facilities Classification (Peak and Average)

Distribution mains and regulator station equipment (both general use and city gate stations) are classified Demand and Commodity using the peak and average ratio for the distribution system. Peak demand is defined as the average of the five-day sustained peaks from the most recent three years. Average daily load is calculated by dividing annual throughput by 365 (days in the year). The average daily load is divided by peak load to arrive at the system load factor of 33.01%. This proportion is classified as commodity related. The remaining 66.99% is classified as demand related. Meters, services and industrial measuring & regulating equipment are classified as customer related distribution plant. Distribution operating and maintenance expenses are classified (and allocated) in relation to the plant accounts they are associated with.

Customer Relations Distribution Cost Classification

Customer service, customer information and sales expenses are the core of the customer relations functional unit which is included with the distribution cost category. For the most part these costs are classified as customer related. Exceptions include uncollectible accounts expense, which is considered separately as a revenue conversion item, and any Demand Side Management amortization expense recorded in Account 908. Any demand side management investment costs and amortization expense included in base rates would be included with the distribution function and classified to demand and commodity by the peak and average ratio. At this point in time, the Company's demand side management investments in base rates have been fully amortized. All current demand side management costs are managed through the Schedule 191 Public Purpose Tariff Rider balancing account which is not included in this cost study.

Distribution Cost Allocation

Demand related distribution costs are allocated to customer groups (rate schedules) by each groups' contribution to the three year average five-day sustained peak. Commodity related distribution costs are allocated to customer groups by annual throughput. Distribution main investment has been segregated into large and small mains. Small mains are defined as less than four inches, with large mains being four inches or greater. The small main costs use the same demand and commodity data, but large usage customers (Schedules 131, and 146) that connect to large system mains have been excluded from the allocations.

Most customer related costs are allocated by the annualized number of customers billed during the test period. Meter investment costs are allocated using the number of customers weighted by the relative current cost of meters in service at December 31, 2010. Services investment costs are allocated using the number of customers weighted by the relative current cost of typical service installations. Industrial measuring and regulating equipment investment costs are allocated by number of turbine meters which effectively excludes small usage customers.

Administrative and General Costs

General and intangible rate base items are allocated by the sum of Underground Storage and Distribution plant. Administrative and general expenses are segregated into plant related, labor related, revenue related and other. The plant related items are allocated based on total plant in service. Labor related items are allocated by operating and maintenance labor expense. Revenue related items are allocated by pro forma revenue. Other administrative and general expenses are allocated 50% by annual throughput (classified commodity related) and 50% by the sum of operating and maintenance expenses not including purchased gas cost or administrative & general expenses. Whenever costs are allocated by sums of other items within the study, classifications are imputed from the relationship embedded in the summed items.

Special Contract Customer Revenue

Three special contract customers receive transportation service from the Company. Rates for these customers were individually negotiated to cover any incremental costs and retain some contribution to margin. The rates for these customers are not being adjusted in this case. The revenue from these special contract customers has been segregated from general rate revenue and allocated back to all the other rate classes by relative rate base. In treating these revenues like other operating revenues their system contribution reduces costs for all rate schedules.

Revenue Conversion Items

In this study uncollectible accounts and commission fees have been classified as revenue related and are allocated by pro forma revenue. These items vary with revenue and are included in the calculation of the revenue conversion factor. Income tax expense items are allocated to schedules by net income before income tax less interest expense.

For the functional summaries on pages 2 and 3 of the cost of service study, these items are assigned to the component cost categories. The revenue related expense items have been reduced to a percent of all other costs and loaded onto each cost category b that ratio. Similarly, income tax items have been assigned to cost categories by relative rate base (as is net income).

The following matrix outlines the methodology applied in the Company Base Case natural gas cost of service study.

IPUC Case No. AVU-G-11-01 Methodology Matrix
Avista Utilities Idaho Jurisdiction
Natural Gas Cost of Service Methodology

Line	Account	Functional Category	Classification	Allocation
	Underground Storage Plant			
1	350 - 357 Underground Storage	Underground Storage	Commodity	E08 Winter throughput
	Distribution Plant			
2	374 Land	Distribution	Demand/Commodity/Customer from Other Dist Plant	S05 Sum of accounts 376-385
3	375 Structures	Distribution	Demand/Commodity/Customer from Other Dist Plant	S05 Sum of accounts 376-385
4	376(S) Small Mains	Distribution	Demand/Commodity by Peak & Average	D02/E06 Coincident peak, annual therms (both excl lg use cust)
5	376(L) Large Mains	Distribution	Demand/Commodity by Peak & Average	D01/E01 Coincident peak (all), annual throughput (all)
6	378 M&R General	Distribution	Demand/Commodity by Peak & Average	D01/E01 Coincident peak (all), annual throughput (all)
7	379 M&R City Gate	Distribution	Demand/Commodity by Peak & Average	D01/E01 Coincident peak (all), annual throughput (all)
8	380 Services	Distribution	Customer	C02, Customers weighted by current typical service co:
9	381 Meters	Distribution	Customer	C03, Customers weighted by average current meter cos
10	385 Industrial M&R	Distribution	Customer	C06, Large use customers
11	387 Other	Distribution	Demand/Commodity/Customer from Other Dist Plant	S05 Sum of accounts 376-385
	General Plant			
12	389-399 All General Plant	Common	Demand/Commodity/Customer from UG & D Plant	S03 Sum of Underground Storage and Distribution Plant in Service
	Intangible Plant			
13	303 Misc Intangible Plant	Distribution	Demand/Commodity/Customer from Dist Plant	S15 Sum of Distribution Plant in Service
14	303 Computer Software	Common	Demand/Commodity/Customer from UG & D Plant	S03 Sum of Underground Storage and Distribution Plant in Service
	Reserve for Depreciation			
15	Underground Storage	Underground Storage	Commodity same as related plant	Allocations linked to related plant accounts
16	Distribution	Distribution	Demand/Commodity/Customer same as related plant	Allocations linked to related plant accounts
17	General	Common	Demand/Commodity/Customer same as related plant	Allocations linked to related plant accounts
18	Intangible	Distribution/Common	Demand/Commodity/Customer same as related plant	Allocations linked to related plant accounts
	Other Rate Base			
19	Accumulated Deferred FIT	All	Demand/Commodity/Customer from Plant in Service	S17 Sum of Total Plant in Service
20	Constuction Advances	Distribution	Customer	C10 Residential only
21	Gas Inventory	Underground Storage	Commodity from Underground Storage Plant	S14 Sum of Underground Storage Plant in Service
22	Gain on Sale of Office Bldg	Common	Demand/Commodity/Customer from UG & D Plant	S03 Sum of Underground Storage and Distribution Plant in Service
23	DSM Investment	Distribution	Demand/Commodity by Peak & Average	D01/E01 Coincident peak (all), annual throughput (all)
	Purchased Gas Expenses			
24	804 Purchased Gas Cost	Production	Demand/Commodity from PGA Tracker WACOG	D05/E07 PGA Demand / PGA Commodity
25	813 Other Gas Expenses	Production	Commodity	E01/E04 Annual Throughput / Annual Sales Therms
	Underground Storage O&M			
26	814 - 837 Underground Storage Exp	Underground Storage	Commodity	E08 Winter throughput

IPUC Case No. AVU-G-11-01 Methodology Matrix
Avista Utilities Idaho Jurisdiction
Natural Gas Cost of Service Methodology

Line	Account	Functional Category	Classification	Allocation
	Distribution O&M			
1	870 OP Super & Engineering	Distribution	Demand/Commodity/Customer from Dist Plant	S15 Sum of Distribution Plant in Service
2	871 Load Dispatching	Distribution	Commodity	E01 Annual throughput
3	874 Mains & Services	Distribution	Demand/Commodity/Customer from related plant	S06 Sum of Mains and Services Plant in Service
4	875 M&R Station - General	Distribution	Demand/Commodity from related plant	S08 Sum of Meas & Reg Station - General Plant in Service
5	876 M&R Station - Industrial	Distribution	Customer from related plant	S19 Sum of Meas & Reg Station - Industrial Plant in Service
6	877 M&R Station - City Gate	Distribution	Demand/Commodity from related plant	S09 Sum of Meas & Reg Station - City Gate Plant in Service
7	878 Meter & House Regulator	Distribution	Customer from related plant	S07 Sum of Meter and Installation Plant in Service
8	879 Customer Installations	Distribution	Customer	C05, Customers weighted by average current meter cos
9	880 Other OP Expenses	Distribution	Demand/Commodity/Customer from other dist expenses	S04 Sum of Accounts 870 - 879 and 881 - 894
10	881 Rents	Distribution	Demand/Commodity/Customer from other dist expenses	S04 Sum of Accounts 870 - 879 and 881 - 894
11	885 MT Super & Engineering	Distribution	Demand/Commodity/Customer from Dist Plant	S15 Sum of Distribution Plant in Service
12	886 MT of Structures	Distribution	Demand/Commodity/Customer from Other Dist Plant	S05 Sum of accounts 376-385
13	887 MT of Mains	Distribution	Demand/Commodity from related plant	S21 Sum of Distribution Mains Plant in Service
14	889 MT of M&R General	Distribution	Demand/Commodity from related plant	S08 Sum of Meas & Reg Station - General Plant in Service
15	890 MT of M&R Industrial	Distribution	Customer from related plant	S19 Sum of Meas & Reg Station - Industrial Plant in Service
16	891 MT of M&R City Gate	Distribution	Demand/Commodity from related plant	S09 Sum of Meas & Reg Station - City Gate Plant in Service
17	892 MT of Services	Distribution	Customer from related plant	S20 Sum of Services Plant in Services
18	893 MT of Meters & Hs Reg	Distribution	Customer from related plant	S07 Sum of Meter and Installation Plant in Service
19	894 MT of Other Equipment	Distribution	Demand/Commodity/Customer from Dist Plant	S15 Sum of Distribution Plant in Service
	Customer Accounting Expenses			
20	901 Supervision	Customer Relations	Customer	C01 All customers (unweighted)
21	902 Meter Reading	Customer Relations	Customer	C01 All customers (unweighted)
22	903 Customer Records & Collections	Customer Relations	Customer	C01 All customers (unweighted)
23	904 Uncollectible Accounts	Revenue Conversion	Revenue	R03 Retail Sales Revenue
24	905 Misc Cust Accounts	Customer Relations	Customer	C01 All customers (unweighted)
	Customer Service & Info Expenses			
25	907 Supervision	Customer Relations	Customer	C01 All customers (unweighted)
26	908 Customer Assistance	Customer Relations	Customer	C01 All customers (unweighted)
27	908 DSM Amortization	Distribution	Demand/Commodity by Peak & Average	D01/E01 Coincident peak (all), annual throughput (all)
28	909 Advertising	Customer Relations	Customer	C01 All customers (unweighted)
29	910 Misc Cust Service & Info	Customer Relations	Customer	C01 All customers (unweighted)
	Sales Expenses			
30	911 - 916 Sales Expenses	Customer Relations	Customer	C01 All customers (unweighted)

IPUC Case No. AVU-G-11-01 Methodology Matrix
Avista Utilities Idaho Jurisdiction
Natural Gas Cost of Service Methodology

Line	Account	Functional Category	Classification	Allocation
	Admin & General Expenses			
1	920 Salaries	Common	Demand/Commodity/Customer from Other O&M	S02/E01 50% O&M excl Gas Purchases and A&G / 50% throughput
2	921 Office Supplies	Common	Demand/Commodity/Customer from Other O&M	S02/E01 50% O&M excl Gas Purchases and A&G / 50% throughput
3	922 Admin Expense Transferred - Credit	Common	Demand/Commodity/Customer from Other O&M	S02/E01 50% O&M excl Gas Purchases and A&G / 50% throughput
4	923 Outside Services	Common	Demand/Commodity/Customer from Other O&M	S02/E01 50% O&M excl Gas Purchases and A&G / 50% throughput
5	924 Property Insurance	Common	Demand/Commodity/Customer from Plant in Service	S17 Sum of Total Plant in Service
6	925 Injuries & Damages	Common	Demand/Commodity/Customer from Other O&M	S02/E01 50% O&M excl Gas Purchases and A&G / 50% throughput
7	926 Pensions & Benefits	Common	Demand/Commodity/Customer from Labpr O&M	S13 O&M Labor Expense
8	927 Franchise Requirements	Common	Demand/Commodity/Customer from Other O&M	S02/E01 50% O&M excl Gas Purchases and A&G / 50% throughput
9	928 Regulatory Commision	Common	Demand/Commodity/Customer from Other O&M	S02/E01 50% O&M excl Gas Purchases and A&G / 50% throughput
10	928 Commission Fees	Revenue Conversion	Revenue	R01 Retail Sales Revenue
11	930 Miscellaneous General	Common	Demand/Commodity/Customer from Other O&M	S02/E01 50% O&M excl Gas Purchases and A&G / 50% throughput
12	931 Rents	Common	Demand/Commodity/Customer from Other O&M	S02/E01 50% O&M excl Gas Purchases and A&G / 50% throughput
13	935 MT of General Plant	Common	Demand/Commodity/Customer from Plant in Service	S17 Sum of Total Plant in Service
	Depreciation Expense			
14	Underground Storage	Underground Storage	Commodity same as related plant	Allocations linked to related plant accounts
15	Distribution	Distribution	Demand/Commodity/Customer same as related plant	Allocations linked to related plant accounts
16	General	Common	Demand/Commodity/Customer same as related plant	Allocations linked to related plant accounts
17	Intangible	Distribution/Common	Demand/Commodity/Customer same as related plant	Allocations linked to related plant accounts
	Taxes			
18	Property Tax	All	Demand/Commodity/Customer from related plant	S14/S15/S16 Sum of UG Plant/Sum of Dist Plant/Sum of Gen Plant
19	Miscellaneous Dist Tax	Distribution	Demand/Commodity/Customer from Dist Plant	S15 Sum of Distribution Plant in Service
20	State Income Tax	Revenue Conversion	Revenue	R02 Net Income before Taxes less Interest Expense
21	Federal Income Tax	Revenue Conversion	Revenue	R02 Net Income before Taxes less Interest Expense
22	Deferred FIT	Revenue Conversion	Revenue	R02 Net Income before Taxes less Interest Expense
23	ITC	Revenue Conversion	Revenue	R02 Net Income before Taxes less Interest Expense
	Operating Revenues			
24	Revenue from Rates	Revenue	Revenue	Pro Forma Revenue per Revenue Study
25	Special Contract Revenue	All	Demand/Commodity/Customer from Rate Base	S01 Sum of Rate Base
26	Off System Sales	Production	Commodity from PGA Tracker	E04 Sales Therms
27	Miscellaneous Service Revenue	Distribution	Demand/Commodity/Customer from Dist Plant	S15 Sum of Distribution Plant in Service
28	Rent From Gas Property	All	Demand/Commodity/Customer from Rate Base	S01 Sum of Rate Base
29	Other Gas Revenue	Underground Storage	Commodity from Underground Storage Plant	S14 Sum of Underground Storage Plant in Service

Sumcost | AVISTA UTILITIES | Natural Gas Utility
Company Base Case | Cost of Service General Summary | Idaho Jurisdiction | 05-Jul-11
AVU-G-04-01 Method | For the Year Ended December 31, 2010

Line	Description (b)	(c)	(d)	(e)	(f) System Total	(g) Residential Service Sch 101	(h) Large Firm Service Sch 111	(j) Interrupt Service Sch 131	(k) Transport Service Sch 146
	Plant In Service								
1	Production Plant								
2	Underground Storage Plant				10,735,000	8,136,564	2,280,462	44,332	273,642
3	Distribution Plant				152,795,000	128,629,327	22,636,021	361,680	1,167,972
4	Intangible Plant				2,596,000	2,172,123	394,779	6,424	22,673
5	General Plant				17,443,000	14,588,194	2,657,728	43,307	153,770
6	Total Plant In Service				183,569,000	153,526,208	27,968,990	455,743	1,618,059
	Accum Depreciation								
7	Production Plant								
8	Underground Storage Plant				(3,819,000)	(2,894,601)	(811,279)	(15,771)	(97,349)
9	Distribution Plant				(54,974,000)	(47,046,745)	(7,418,277)	(117,553)	(391,424)
10	Intangible Plant				(1,264,000)	(1,057,309)	(192,452)	(3,134)	(11,104)
11	General Plant				(5,654,000)	(4,728,639)	(861,480)	(14,038)	(49,843)
12	Total Accumulated Depreciation				(65,711,000)	(55,727,294)	(9,283,488)	(150,497)	(549,721)
13	Net Plant				117,858,000	97,798,914	18,685,502	305,247	1,068,338
14	Accumlulated Deferred FIT				(23,672,000)	(19,797,855)	(3,606,720)	(58,770)	(208,656)
15	Miscellaneous Rate Base				9,216,000	7,089,075	1,880,208	35,807	210,910
16	Total Rate Base				103,402,000	85,090,134	16,958,990	282,283	1,070,592
17	Revenue From Retail Rates				70,514,000	54,493,548	15,413,796	274,603	332,053
18	Other Operating Revenues				130,000	107,243	21,099	350	1,308
19	Total Revenues				70,644,000	54,600,791	15,434,896	274,953	333,361
	Operating Expenses								
20	Purchased Gas Costs				41,884,000	30,760,161	10,917,996	202,857	2,986
21	Underground Storage Expenses				318,000	241,027	67,554	1,313	8,106
22	Distribution Expenses				4,305,000	3,660,598	589,569	7,677	47,156
23	Customer Accounting Expenses				2,008,000	1,953,072	53,717	493	718
24	Customer Information Expenses				373,000	343,522	26,166	415	2,897
25	Sales Expenses				7,000	6,897	102	0	1
26	Admin & General Expenses				5,034,000	4,015,966	893,990	17,569	106,475
27	Total O&M Expenses				53,929,000	40,981,245	12,549,093	230,324	168,338
28	Taxes Other Than Income Taxes				978,000	816,055	150,456	2,468	9,022
29	Depreciation Expense								
30	Underground Storage Plant Depr				182,000	137,946	38,663	752	4,639
31	Distribution Plant Depreciation				3,567,000	3,076,759	458,312	6,544	25,386
32	General Plant Depreciation				1,285,000	1,074,691	195,791	3,190	11,328
33	Amortization of Intangible Plant				425,000	355,464	64,739	1,055	3,742
34	Total Depr & Amort Expense				5,459,000	4,644,860	757,504	11,540	45,095
35	Income Tax				2,724,000	2,127,688	557,987	8,412	29,913
36	Total Operating Expenses				63,090,000	48,569,848	14,015,040	252,744	252,368
37	Net Income				7,554,000	6,030,943	1,419,855	22,209	80,993
38	Rate of Return				7.31%	7.09%	8.37%	7.87%	7.57%
39	Return Ratio				1.00	0.97	1.15	1.08	1.04
40	Interest Expense				3,123,000	2,569,936	512,204	8,526	32,335

Sumcost
Company Base Case
AVU-G-04-01 Method

AVISTA UTILITIES
Summary by Function with Margin Analysis
For the Year Ended December 31, 2010

Natural Gas Utility
Idaho Jurisdiction

05-Jul-11

Line	(b) Description	(c)	(d)	(e)	(f) System Total	(g) Residential Service Sch 101	(h) Large Firm Service Sch 111	(j) Interrupt Service Sch 131	(k) Transport Service Sch 146
	Functional Cost Components at Current Rates								
1	Production				42,042,597	30,876,637	10,959,337	203,625	2,997
2	Underground Storage				1,908,309	1,399,405	450,905	8,317	49,682
3	Distribution				18,697,876	15,857,806	2,655,467	37,972	146,631
4	Common				7,865,217	6,359,699	1,348,087	24,689	132,743
5	**Total Current Rate Revenue**				**70,514,000**	**54,493,548**	**15,413,796**	**274,603**	**332,053**
6	Exclude Cost of Gas w / Revenue Exp.				41,642,086	30,584,995	10,855,822	201,269	0
7	**Total Margin Revenue at Current Rates**				**28,871,914**	**23,908,553**	**4,557,974**	**73,334**	**332,053**
	Margin per Therm at Current Rates								
8	Production				$0.00521	$0.00538	$0.00538	$0.00538	$0.00100
9	Underground Storage				$0.02483	$0.02583	$0.02345	$0.01901	$0.01651
10	Distribution				$0.24329	$0.29269	$0.13809	$0.08677	$0.04874
11	Common				$0.10234	$0.11738	$0.07010	$0.05641	$0.04412
12	Total Current Margin Melded Rate per Therm				**$0.37566**	**$0.44129**	**$0.23702**	**$0.16757**	**$0.11038**
	Functional Cost Components at Uniform Current Return								
13	Production				42,042,597	30,876,637	10,959,337	203,625	2,997
14	Underground Storage				1,893,142	1,434,902	402,165	7,818	48,257
15	Distribution				18,709,971	16,087,390	2,442,420	36,170	143,991
16	Common				7,868,290	6,394,950	1,316,622	24,418	132,300
17	Total Uniform Current Cost				**70,514,000**	**54,793,879**	**15,120,545**	**272,031**	**327,545**
18	Exclude Cost of Gas w / Revenue Exp.				41,642,086	30,584,995	10,855,822	201,269	0
19	Total Uniform Current Margin				**28,871,914**	**24,208,884**	**4,264,723**	**70,762**	**327,545**
	Margin per Therm at Uniform Current Return								
20	Production				$0.00521	$0.00538	$0.00538	$0.00538	$0.00100
21	Underground Storage				$0.02463	$0.02648	$0.02091	$0.01786	$0.01604
22	Distribution				$0.24344	$0.29693	$0.12701	$0.08265	$0.04786
23	Common				$0.10238	$0.11803	$0.06847	$0.05580	$0.04398
24	Total Current Uniform Margin Melded Rate per				**$0.37566**	**$0.44683**	**$0.22177**	**$0.16169**	**$0.10888**
25	**Margin to Cost Ratio at Current Rates**				**1.00**	**0.99**	**1.07**	**1.04**	**1.01**
	Functional Cost Components at Proposed Rates								
26	Production				42,042,454	30,876,532	10,959,300	203,624	2,997
27	Underground Storage				2,139,672	1,621,758	454,537	8,836	54,541
28	Distribution				20,162,728	17,295,903	2,671,339	39,845	155,640
29	Common				8,090,147	6,580,494	1,350,428	24,969	134,255
30	**Total Proposed Rate Revenue**				**72,435,000**	**56,374,687**	**15,435,604**	**277,274**	**347,435**
31	Exclude Cost of Gas w / Revenue Exp.				41,641,944	30,584,890	10,855,785	201,269	0
32	**Total Margin Revenue at Proposed Rates**				**30,793,056**	**25,789,796**	**4,579,819**	**76,006**	**347,435**
	Margin per Therm at Proposed Rates								
33	Production				$0.00521	$0.00538	$0.00538	$0.00538	$0.00100
34	Underground Storage				$0.02784	$0.02993	$0.02364	$0.02019	$0.01813
35	Distribution				$0.26235	$0.31924	$0.13891	$0.09105	$0.05174
36	Common				$0.10526	$0.12146	$0.07022	$0.05706	$0.04463
37	Total Proposed Margin Melded Rate per Therm				**$0.40066**	**$0.47601**	**$0.23816**	**$0.17368**	**$0.11549**
	Functional Cost Components at Uniform Proposed Return								
38	Production				42,042,454	30,876,532	10,959,300	203,624	2,997
39	Underground Storage				2,139,672	1,621,758	454,536	8,836	54,542
40	Distribution				20,162,728	17,295,908	2,671,334	39,845	155,641
41	Common				8,090,147	6,580,495	1,350,427	24,969	134,256
42	Total Uniform Proposed Cost				**72,435,000**	**56,374,693**	**15,435,597**	**277,275**	**347,436**
43	Exclude Cost of Gas w / Revenue Exp.				41,641,944	30,584,890	10,855,785	201,269	0
44	Total Uniform Proposed Margin				**30,793,056**	**25,789,802**	**4,579,812**	**76,006**	**347,436**
	Margin per Therm at Uniform Proposed Return								
45	Production				$0.00521	$0.00538	$0.00538	$0.00538	$0.00100
46	Underground Storage				$0.02784	$0.02993	$0.02364	$0.02019	$0.01813
47	Distribution				$0.26235	$0.31924	$0.13891	$0.09105	$0.05174
48	Common				$0.10526	$0.12146	$0.07022	$0.05706	$0.04463
49	Total Proposed Uniform Margin Melded Rate pe				**$0.40066**	**$0.47601**	**$0.23816**	**$0.17368**	**$0.11549**
50	**Margin to Cost Ratio at Proposed Rates**				**1.00**	**1.00**	**1.00**	**1.00**	**1.00**
51	**Current Margin to Proposed Cost Ratio**				**0.94**	**0.93**	**1.00**	**0.96**	**0.96**

Sumcost	AVISTA UTILITIES	Natural Gas Utility	
Company Base Case	Summary by Classification with Unit Cost Analysis	Idaho Jurisdiction	05-Jul-11
AVU-G-04-01 Method	For the Year Ended December 31, 2010		

Line	(b) Description	(c)	(d)	(e)	(f) System Total	(g) Residential Service Sch 101	(h) Large Firm Service Sch 111	(j) Interrupt Service Sch 131	(k) Transport Service Sch 146
	Cost by Classification at Current Return by Schedule								
1	Commodity				42,449,821	30,973,589	11,025,802	247,875	202,556
2	Demand				14,994,089	11,246,356	3,651,587	25,425	70,721
3	Customer				13,070,090	12,273,603	736,408	1,304	58,775
4	Total Current Rate Revenue				70,514,000	54,493,548	15,413,796	274,603	332,053
	Revenue per Therm at Current Rates								
5	Commodity				$0.55233	$0.57169	$0.57335	$0.56640	$0.06733
6	Demand				$0.19509	$0.20758	$0.18989	$0.05810	$0.02351
7	Customer				$0.17006	$0.22654	$0.03829	$0.00298	$0.01954
8	Total Revenue per Therm at Current Rates				$0.91749	$1.00580	$0.80154	$0.62748	$0.11038
	Cost per Unit at Current Rates								
9	Commodity Cost per Therm				$0.55233	$0.57169	$0.57335	$0.56640	$0.06733
10	Demand Cost per Peak Day Therms				$23.50	$22.94	$27.93	$12.18	$4.78
11	Customer Cost per Customer per Month				$14.68	$13.99	$56.80	$108.69	$816.32
	Cost by Classification at Uniform Current Return								
12	Commodity				42,398,967	31,055,515	10,897,094	246,421	199,937
13	Demand				14,961,942	11,343,446	3,524,781	24,349	69,367
14	Customer				13,153,090	12,394,918	698,671	1,261	58,241
15	Total Uniform Current Cost				70,514,000	54,793,879	15,120,545	272,031	327,545
	Cost per Therm at Current Return								
16	Commodity				$0.55167	$0.57320	$0.56666	$0.56308	$0.06646
17	Demand				$0.19468	$0.20937	$0.18329	$0.05564	$0.02306
18	Customer				$0.17114	$0.22878	$0.03633	$0.00288	$0.01936
19	Total Cost per Therm at Current Return				$0.91749	$1.01135	$0.78629	$0.62160	$0.10888
	Cost per Unit at Uniform Current Return								
20	Commodity Cost per Therm				$0.55167	$0.57320	$0.56666	$0.56308	$0.06646
21	Demand Cost per Peak Day Therms				$23.45	$23.13	$26.96	$11.66	$4.69
22	Customer Cost per Customer per Month				$14.77	$14.13	$53.89	$105.06	$808.90
23	**Revenue to Cost Ratio at Current Rates**				**1.00**	**0.99**	**1.02**	**1.01**	**1.01**
	Cost by Classification at Proposed Return by Schedule								
24	Commodity				42,982,919	31,486,684	11,035,359	249,383	211,494
25	Demand				15,617,416	11,854,504	3,661,027	26,542	75,343
26	Customer				13,834,665	13,033,499	739,218	1,349	60,598
27	Total Proposed Rate Revenue				72,435,000	56,374,687	15,435,604	277,274	347,435
	Revenue per Therm at Proposed Rates								
28	Commodity				$0.55927	$0.58116	$0.57385	$0.56985	$0.07030
29	Demand				$0.20320	$0.21880	$0.19038	$0.06065	$0.02504
30	Customer				$0.18001	$0.24056	$0.03844	$0.00308	$0.02014
31	Total Revenue per Therm at Proposed Rates				$0.94248	$1.04052	$0.80267	$0.63358	$0.11549
	Cost per Unit at Proposed Rates								
32	Commodity Cost per Therm				$0.55927	$0.58116	$0.57385	$0.56985	$0.07030
33	Demand Cost per Peak Day Therms				$24.48	$24.18	$28.01	$12.71	$5.09
34	Customer Cost per Customer per Month				$15.54	$14.85	$57.02	$112.45	$841.64
	Cost by Classification at Uniform Proposed Return								
35	Commodity				42,982,919	31,486,685	11,035,355	249,384	211,494
36	Demand				15,617,415	11,854,506	3,661,024	26,542	75,343
37	Customer				13,834,666	13,033,501	739,217	1,349	60,599
38	Total Uniform Proposed Cost				72,435,000	56,374,693	15,435,597	277,275	347,436
	Cost per Therm at Proposed Return								
39	Commodity				$0.55927	$0.58116	$0.57385	$0.56985	$0.07030
40	Demand				$0.20320	$0.21880	$0.19038	$0.06065	$0.02504
41	Customer				$0.18001	$0.24056	$0.03844	$0.00308	$0.02014
42	Total Cost per Therm at Proposed Return				$0.94248	$1.04052	$0.80267	$0.63359	$0.11549
	Cost per Unit at Uniform Proposed Return								
43	Commodity Cost per Therm				$0.55927	$0.58116	$0.57385	$0.56985	$0.07030
44	Demand Cost per Peak Day Therms				$24.48	$24.18	$28.01	$12.71	$5.09
45	Customer Cost per Customer per Month				$15.54	$14.85	$57.02	$112.45	$841.65
46	**Revenue to Cost Ratio at Proposed Rates**				**1.00**	**1.00**	**1.00**	**1.00**	**1.00**
47	**Current Revenue to Proposed Cost Ratio**				**0.97**	**0.97**	**1.00**	**0.99**	**0.96**

Sumcost
Company Base Case
AVU-G-04-01 Method

AVISTA UTILITIES
Customer Cost Analysis
For the Year Ended December 31, 2010

Natural Gas Utility
Idaho Jurisdiction

05-Jul-11

Line	(b) Description	(c)	(d)	(e)	(f) System Total	(g) Residential Service Sch 101	(h) Large Firm Service Sch 111	(j) Interrupt Service Sch 131	(k) Transport Service Sch 146
	Meter, Services, Meter Reading & Billing Costs by Schedule at Requested Rate of Return								
	Rate Base								
1	Services				47,354,000	46,636,256	689,043	1,913	26,788
2	Services Accum. Depr.				(22,086,000)	(21,751,243)	(321,371)	(892)	(12,494)
3	Total Services				25,268,000	24,885,013	367,672	1,021	14,294
4	Meters				19,748,000	17,209,262	2,430,764	5,496	102,479
5	Meters Accum. Depr.				(4,844,000)	(4,221,271)	(596,244)	(1,348)	(25,137)
6	Total Meters				14,904,000	12,987,991	1,834,520	4,148	77,342
7	Total Rate Base				40,172,000	37,873,004	2,202,192	5,169	91,636
8	Return on Rate Base @ 8.55%				3,410,603	3,215,418	186,966	439	7,780
9	Revenue Conversion Factor				0.63778	0.63778	0.63778	0.63778	0.63778
10	**Rate Base Revenue Requirement**				**5,347,616**	**5,041,579**	**293,151**	**688**	**12,198**
	Expenses								
11	Services Depr Exp				1,359,000	1,338,402	19,775	55	769
12	Meters Depr Exp				673,000	586,481	82,839	187	3,492
13	Services Maintenance Exp				345,000	339,771	5,020	14	195
14	Meters Maintenance Exp				301,000	262,304	37,050	84	1,562
15	Meter Reading				228,000	224,659	3,319	3	18
16	Billing				1,505,000	1,482,948	21,910	20	122
17	Total Expenses				4,411,000	4,234,565	169,913	363	6,158
18	Revenue Conversion Factor				0.996296	0.996296	0.996296	0.996296	0.996296
19	**Expense Revenue Requirement**				**4,427,399**	**4,250,308**	**170,545**	**365**	**6,181**
20	**Total Meter, Service, Meter Reading, and**				**9,775,016**	**9,291,887**	**463,696**	**1,053**	**18,380**
21	Total Customer Bills				890,486	877,438	12,964	12	72
22	**Average Unit Cost per Month**				**$10.98**	**$10.59**	**$35.77**	**$87.72**	**$255.27**
	Fixed Costs per Customer								
23	Total Customer Related Cost				13,834,666	13,033,501	739,217	1,349	60,599
24	Customer Related Unit Cost per Month				$15.54	$14.85	$57.02	$112.45	$841.65
25	Other Non-Gas Costs				16,958,390	12,756,301	3,840,594	74,657	286,837
26	Other Non-Gas Unit Cost per Month				$19.04	$14.54	$296.25	$6,221.41	$3,983.85
27	**Total Fixed Unit Cost per Month**				**$34.58**	**$29.39**	**$353.27**	**$6,333.86**	**$4,825.50**